BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket No. ER04-699-000
ENTERGY SERVICES, INC.:
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ENTERGY SERVICES, INC.: Docket Nos. ER03-1272-002
\- - - - - - - - - - - - x ER03-1272-003

Mississippi Department of Education
359 North West Street
Jackson, Mississippi

Friday, October 8, 2004

The above-entitled matter came on for technical conference, pursuant to notice

TAKEN BY: Allison D. Peppers,
Court Reporter & Notary Public

APPEARANCES:

PAT WOOD, III,
FEDERAL ENERGY REGULATORY COMMISSION
NEILSON COCHRAN,
MISSISSIPPI PUBLIC SERVICE COMMISSION
MICHAEL CALLAHAN,
MISSISSIPPI PUBLIC SERVICE COMMISSION
MICHAEL SCHNITZER,
THE NORTHBRIDGE GROUP, INC.
KEN TURNER,
ENTERGY SERVICES, INC.
KIMBERLY DESPEAUX,
ENTERGY SERVICES, INC
JIMMY SMITH
ENTERGY SERVICES, INC.
LYNNE MACKEY
INTERGEN NORTH AMERICA
JOE MARRONE,
OCCIDENTAL ENERGY VENTURES
MARVIN CARRAWAY,
MISSISSIPPI DELTA ENERGY AGENCY
BRIAN ADAMS,
NRG ENERGY, INC.

-- CONTINUED --

APPEARANCES (CONTINUED):

JOLLY HAYDEN,
    CALPINE ENERGY SERVICES
JOHN CONWAY,
    EAST TEXAS ELECTRIC COOPERATIVE
GARY NEWELL,
    LAFAYETTE UTILITIES
BOB WEISHAAR,
    SOUTHEAST ELECTRIC CONSUMERS ASSOCIATION
NICK BROWN,
    SOUTHWEST POWER TOOL
JESS TOTTEN,
    PUBLIC UTILITY COMMISSION OF TEXAS

P R O C E E D I N G S

MR. WOOD: Good morning. On behalf of the Federal Energy Regulatory Commission, and on behalf of my colleague Joe Keller and our staff, I'd like to express our appreciation to our colleagues from the Mississippi Commission, Vice Chairman Cochran and Commissioner for your hospitality in getting us this nice meeting space to continue our regional discussions on a number of pending dockets from Entergy to add wholesale procurement programs and independent systems, independent coordinator of transmission proposal before our commission before the different states for their review --

Before we go any further, I'd like to just turn it over to Commissioner Callahan and Vice Chairman Cochran for any thoughts they may have.

MR. COCHRAN: Welcome to Jackson. I'm glad you're here to participate. We apologize for the inclement weather. We need the rain, so we appreciate whatever we can get at this precise moment.

But again, thanks to Chairman Wood and those members of staff here to discuss something that is very important and, to some degree, some think is a very urgent issue. We look forward to in-depth discussion to see where we are and where we go from here.

But, again, welcome to Jackson. Some have asked about lunch. Obviously, you're on your own; it's going to be hectic. There's a couple of nice restaurants down on Capitol Street. We do have a cafeteria in our building over at the Woolthall Building. It's not what you would call a Five-Star cafeteria, but it certainly can be of assistance to you.

Again, welcome to Jackson. We've been looking forward to today.

MR. CALLAHAN:

Again, I'd just like to reiterate what Mr. Cochran said. We're glad to have you all in Jackson.

As most of you know, I'm from Hattiesburg, which is about 100 miles south of here, which happens to be home to the University of Southern Mississippi, which happened to beat Houston last night and happens to be 4 and 0. It's the only undefeated team in the state of Mississippi. Football's big in the South.

But anyway, we're glad to have you here, and like Mr. Cochran said, we're sorry about the weather. But we've been about 30 days without rain, and my yard needs it. My golf course needs it, so we're glad to see it coming.

We're looking forward to this today. I hope that this will be maybe a little bit more informative that what we had in New Orleans, and we can proceed on some of the issues that deal a little more directly with the Entergy filing. We're excited. We have actually had our hearing in Jackson on the Entergy proposal at the end of August. It was a very good hearing. A lot of issues were brought forth. A lot of progress was made, and we're right now awaiting -- the filing Entergy actually made in Mississippi was more of an informational filing that does not require an order by the Commission. But we're hoping that maybe after this hearing, and whatever else happens, that we will be able to send a letter to you, Chairman Wood, and kind of tell you what our thoughts are on the filing and what we think about everything and how we'd like to see it proceed. And certainly, at that point, feel free to do whatever you want with the letter. It's up to you.

We're glad for y'all to be in Jackson. One more thing on lunch I might suggest. Right over here north of us is the Department of Transportation building. They also have a cafeteria, and it's probably better than the one we have in the Woolthall Building. That might be an option, too. It's right across the block, go down, I think it's in the basement of their building, and they have pretty good food as well.

But in the meantime, welcome to Jackson. We look forward to having a very productive day today.

Mr. Chairman?

MR. WOOD:

Thank you, Commissioner.

I want to recognize our colleagues also from the other states. We've got right down here on the end, Jess Totten from the Public Utility Commission of Texas. Welcome, Jess. Paul Nordstrom representing the New Orleans City Council, one of the five jurisdictional regulators here. And Chairman Sandra Hochstetter from Arkansas.

I want to also recognize our staff because they'll be participating today, probably a little more than did the New Orleans staff. We've got Christy Walsh and John Rogers. John is our FERC -- one of our two FERC staff at the office in Little Rock. We also had several that helped coordinate this conference, and I know that you had a lot of help from your office, Mike. And I want to recognize Donna. Donna, thank you for your help. Steve Rodgers, who is at the table with us. Anna Cochrane, Mike Bardee and Steve Rodgers who have been working with us on matters related to the Entergy filing. So that's just to make the introductions today.

We did meet, after this filing was made, earlier this year. We did have a meeting in New Orleans. It's my hope today that a more informal format, and more workshop format, perhaps, that we practice more ways to bridge the differences between what the company has proposed and what the market participants, who would benefit if this program were set up, say is important to them. We need to work with them and try and see if we could find some common ground and build upon where we left it.

Since that time, we've had a number of events, and I want to turn it over now to Steve Rodgers. We're going to walk through the calendar since we last met.

MR. RODGERS:

Thank you, Mr. Chairman.

I thought what Mr. Callahan had to say was a good segue into one of the things that we wanted to do to kick off this conference, which is to hear a report from each of the state jurisdictions in terms of what's happening, in the various proceedings that are pending before them. So with that, I'd like to call on Chairman Hochstetter to get this report on the status of the findings for Arkansas.

MS. HOCHSTETTER:

Thank you, Chairman Wood.

We had issued a docket, just to back up a moment, back in April this year to look at the pros and cons of Entergy pursuing an ITT proposal with FERC versus joining the FPP RTO which will be covering a substantial portion of the State of Arkansas. And within that docket, we had comments, reply comments, and also most recently, subsequent to the July technical conference in New Orleans, a series of data requests that we asked Entergy to respond to. They have responded to this data request. Responses were filed a couple of weeks ago, and we're in the process of evaluating those responses and doing that in the context of these proceedings that FERC is conducting.

And I recognize that there have been some meetings between Entergy and some of the stakeholders over the last couple of weeks, so with our docket pending and the parallel proceeding at FERC, we'll hopefully be able to work synergistically towards a resolution of, as Chairman Woods phrase it, what the most appropriate common ground is between the different options out there.

MR. RODGERS:

Thank you, Chairman.

If we could have Paul Nordstrom from the New Orleans City Council give us a report on the state of your agency.

MR. NORDSTROM:

Thank you, Steve. My name is Paul Nordstrom. I'm outside counsel to the New Orleans City Council.

The council sends it's regrets for not being able to attend today, but they've asked me, as outside counsel, and Kelly Meehan, who is the director of the utility's office, to fill in for them.

I think the City Council is in a procedural status pretty similar, actually, to the Mississippi commission. The council held a public hearing on the ICT proposal in the spring of this year. It was an informational hearing. The council has not required a formal filing or set up a formal docket on the ICT proposal. It has, though, conducted informal discovery, and we're very actively monitoring the informational flow in the other jurisdictions and of course are participating in settings like this.

Obviously, I can't speak with 100% certainty for our client, but I think that we probably are in a similar situation to Mississippi that at some point this fall, the council could send the requested letter to FERC in connection with its position on the proposal.

MR. RODGERS:

Thank you, Paul. I would next like to call Jess Totten who is here today on behalf of the public utility commission of Texas.

MR. TOTTEN:

Thank you, Steve. I'm Jess Totten, director of the electrical division of the Texas Public Utilities Commission.

We have had related proceedings pending in Texas, both at the time of the first technical conference and today. So the commissioners have felt unable to attend the technical conference because of ex parte concerns.

The earlier case was a retail case, but it involved what kind of independent organization Entergy might create in a wholesale market. The case is no longer pending, but we do have an Entergy rate case that the Commission deliberated on last week and decided to dismiss for reasons related to the development of the wholesale market. So because the case is still pending, the commissioners were not able to come to this meeting. We have not really focused on presenting our views to the FERC on this argument largely because of the ex parte issues. If we get these other cases cleared up, it's possible we could do that.

MR. RODGERS:

Just to give the audience an update on what the state of play as it was meant in the final opinion before the FERC since the New Orleans meeting at the New Orleans meeting there were issues raised by several market participants in terms of desire and a better understanding of what products Entergy is interested in soliciting through its current procurement process and there was a desire for more transparency behind the process. So in response to that, two, what I would call, mini technical conferences have been held up at FERC headquarters; one in late August and one in late September, that addressed those issues. And FERC Staff was there; it was open to the public. And I feel that there was some progress that was made on the hearing of issues that took place at these technical conferences.

FERC also issued a data request on August 17 to Entergy and has gotten a response back on that. But I think part of how we're going to proceed this morning is, this morning's program will be on Entergy's proposal for a wholesale procurement process, a weekly process, that is different from the current process. We're going to hear a report from Entergy about, not only the developments related to that, but also, a status report on what developments have taken place as a result of the two mini technical conferences that were held with FERC.

After Entergy is done with that presentation, we intend to have several market participants come join us at the table with Entergy, and we'd like to hear your response -- your reaction in terms of where progress has been made and where there are issues that still remain, if any. We're also hoping that throughout the day that there will be a more interactive dialogue exchange, not only between commissioners and the panelists, but also among the panelists themselves. This afternoon's session will be focused on the independent coordinator of the transmission proposal. But more on that later.

Let me turn it over to Entergy.

MR. HURSTELL:

Thank you, Steve. I am John Hurstell, vice president of -- fuel and generation operations at Entergy Services. And joining me at the table are Ken Turner, Michael Schnitzer and Mac Norton.

I am going to begin the discussion by talking about our current process and give an update on our take on the two mini technical conferences.

MR. CALLAHAN:

Mr. Chairman, some people in the back are shaking their heads.

MR. HURSTELL:

After I talk about our current process, then Ken Turner is going to address the new WPP.

What this is, this is a combination of two presentations that we gave at the mini technical conferences, with a few updates. I think everyone has a copy of it, so we will just walk through.

I'm going to try to skip through a lot of the -- I'm just going to try to get the hit points of this. And just as an overview, what we're going to do is talk about the weekly process as it exists right now.

Just for the sake of some clarity, we refer to the current process as the weekly RFP. The future process is the WPP, just to make that distinction. But we think it is helpful to look at what we do now because I think it is an indicator of what kind of success we can have in the future.

We're going to talk a little bit about the current process. We're going to give you some statistics related to the current weekly process. There was definite decline in the purchase in the weekly market, but we want to go through some of the reasons for that. As specifically requested at the meeting in New Orleans because we provided descriptions of the products that we would like to receive offers for in the weekly RFP.

Here we have some answers to some common questions that we got at the New Orleans meeting and the technical conferences. This just provides a little insight into the history of the WPP and the weekly RFP that started in late 2001. And we asked for input from our participants, and we got that input.

Here's a listing of all the participants in one of the first two meetings to develop the weekly RFP, and we were very pleased that we got such a large number of participants. I should also point out that there were others invited that didn't participate. But as you can see, this is a pretty broad mix of the participants in the market.

Moving on to Slide 5. In the past few years, there have been over 1000 offers made to us in the weekly RFP market. With a kilo capacity of almost 300,000 megawatts, we have selected from those offers about 84,000 megawatts, or about 23 percent of the offers made have been accepted. Now, this was something that came out of the technical conference; we got plenty of questions about how successful different market participants have been -- I'm moving to Slide 6 -- in the weekly market.

And as you can see, here is a listing for every offer that we received, and the success rates range from as high as 100 percent to as low as 9 percent for those that were participating regularly. We have 11 participants that may have submitted one or two offers Over the course of the last few years, and we just consolidated those. But you can see that, for example, from the M -- M participated in many weeks. And when they participate, they know how to sell us power. They give us what we need, and they've been successful 100 percent of the time.

The next slide really just talks about the key components of the weekly audit. And that is the heat rate, the fuel adder and the flexibility of everybody. And what very seldom gets talked about is the fuel adder. Let me just give you an example of how that works. When someone offers us a heat rate, they have to specify how that works. Well, instead of everyone specifying different NCs, we tell them we're going to use the Henry Power index, and you tell us what adjustment we need to make to those indices to account for the gas that you're pumping.

Here's an example. An 8000 heat rate is usually a good offer to us, and without considering the gas fuel adder, at $6 gas an 8000 heat rate is $48. But if you turn the page, you'll see that we get fuel adder ranging from zero to $1. So if add a 50-cent fuel adder, then that turns your $48 power into $52 power and effectively raises your heat rate from 8000 to 8667. So that's why we're trying to have a discussion where we're strictly talking about heat rates, and that's only one component of an offer that we have to consider. I think some of the market participants don't consider fully the impact of fuel adder in our particular need.

Flexibility has been a big topic, and at the

New Orleans conference, there were some issues of whether the people realized we were asking for flexibility. And that was one of things we were trying to correct with the technical conference. But of over the 1000 offers that we have received in the weekly market, only about 4 percent of them have provided current-day flexibility of any kind. And of those that were offered, we accepted about 16% of those. Now, the reason why we accepted such a small percentage is because the offers have generally included very high minimum run rates as compared to our own generation. And we're going to talk about an example of that later. But the impact of that is that they offered us flexibility, but at a very high price, and even the flexibility that was offered was generally in the range of 50 to 100 megawatts. Which when you consider that in single unit that we may offer that may be a 500-megawatt unit, it may be able to get down to as low as 50 megawatts. So a single unit on our system provides us 450 megawatts of flexibility, whereas the best offers we could get were generally in the 50-megawatt range.

Now, this graph shows a comparison of the offers we've received in the weekly market versus what's been accepted. You can see that we started out pretty slow, but then we accelerated during the summer of 2003, and we're very pleased with that. And then you can see there's been a little dip since March in terms of our purchases. And I'd like to talk on the next slide about why that is the case.

Since that time period, there's been an increase in coal and nuclear generation on our system compared to previously. There's no new sources on our system, it could be just the re-fueling schedule, It could just be the coal units, but there's more on our system. And, of course, we're going to make use of as much nuclear and coal as we can. Second, and this is another thing I think is frequently ignored in these technical conferences, is the price of Number 6 oil has made it much more economical than natural gas.

MR. WOOD:

How many of the units here have participated in your weekly RFP relief --

MR. SCHNITZER:

In our units?

MR WOOD:

No. Well, do your units participate as well?

MR. SCHNITZER:

Well, essentially, they do because we are comparing offers to what we can do with our own units, and we have -- I think we have 2000 megawatts of capability primarily here in the state of Mississippi. But as far as

I know, there aren't any IPPs in our region that can burn Number 6 oil. I think there's 1 that can burn Number 2 oil, but Number 2 oil is considerably more expensive than Number 6.

The third issue is the differential that we've -- over the last 2 years, and with all of the QF's -- and we have to take the power from them. So that is displaced --

MR. WOOD:

Now, are they participating in all of the RFPs or are they --

MR. SCHNITZER:

Well, it's -- yes. They can participate by putting in some bids. I don't know how successful they've been because they do have that right. I don't know that they really have a strong incentive to be very competitive in the weekly market because they do have the hourly input. I think there have been some that have submitted bids.

MR. WOOD:

Was the rate schedule that you --

MR. SCHNITZER:

Well, right now, that is -- we have 3 active cases going on as to what our reporting cost is. And right now, it's based on the combination of our generation and this purchase that we could have made into our -- we're real close to reaching a settlement on those issues in both Louisiana and Texas, and we just had a case -- a docket open in Arkansas.

And then the fourth point is that there's been a greater -- of long-term purchases. We've locked into some long-term fields with some of the IPPs. Now, those basically come into our mix at a cost -- on a cost basis. They're much more competitive than those parties that have to bid their cost plus an option.

The next few slides talk about some of the specifics on each of the -- so I want to kind of glide through those rather quickly except to show you 1 slide, and that is on Page 19. Even with the decrease in purchases in the weekly market -- weekly RFP. What this graph shows is the energy from Entergy's own gas-powered generation, and you can see the significant drop from 2002 to the present. So when we displace in the weekly market, it doesn't mean we're running our gas-powered operation. It's the other sources I'm talking about.

MR. WOOD:

What would the -- Slide 18 -- John, what would --

MR. HURSTELL:

I don't have that number with me, but we can get you that.

MR. WOOD:

In the ball park. Would that be greater or less than the slide that --

MR. SCHNITZER:

It would be less. It'd be less. 24 hours a day, and the average is about 1300 megawatts. 24 hours a day, and the average is about 1300 megawatts. We just keep scheduling flexibility, so the energy is going to be much less than that.

MR. WOOD:

Are the IPP contracts from the --

MR. SCHNITZER:

Either they're over the peaks, or we may even have dispatch instantaneously.

I'm up to Slide 20, and I apologize for flying through this. We did provide a review for the merchants on what products we'd like to see offered in the weekly RFP. And I guess the most important thing we'd like to cover is the -- Slide 22. This came out of the technical conference.

In our first technical conference, some of the marketers expressed a concern that by submitting bids on the weekly market, they were committing their capacity for a week, and then they may be missing out on opportunities to capture uptakes in the market later in a week. So what we said is that we work with them to come up with what they're calling a "recallable" product that they can put a bid in and reserve the right to pull it back on a 24-hour notice. We're trying to do everything we can to accommodate their -- what flexibility they need. And we have a workshop scheduled for mid-November with those generators who are interested in working with us on the development of that product.

The last thing I'd like to cover is common -- what I like to refer to as the common question. The first is, what can merchants do to increase the weekly RFP sales. The second is, why do we operate generators with a 10,000 Btu and kilowatt-hour heat rate and reject offers from IPP with lower heat rates. And third, why don't we provide feedback on why offers are rejected. And I think as we talk about it today, we believe that the reason -- merchants can increase their sales in a weekly market by lowering their heat rate, lowering the fuel adder, lowering the minimum taper positions and providing more flexibility. I don't think we can say it any more clearly than that.

The next thing -- I'll just take a little time on this.

MR. WOOD:

What are the parameters or minimum --

MR. SCHNITZER:

We have a bid sheet. It's included in the presentation as part of the appendix where they can specify each hour; what's the minimum megawatt hour we have to take and what's the maximum megawatt hours that we can take. So if they wanted to bid flexibility, they could say the minimum you have to take is 50 and the maximum you can take is 400. That's the kind of bids we'd like to see. In general, the flexibility does -- see, limits offered is -- you can take 200 -- you have to take 200. You can take 250, and occasionally -- I think there was even one time where we offered 200 megawatts. But generally, the flexibility that we're offered is the 50 to 100 range. But the way they do it is on that big sheet.

MR. WOOD:

So the heat rate is generally different for the higher quantities?

MR. SCHNITZER:

They could do that. The could say you -- it could be both, really. It's quite more common. At the minimum, you might have a 9000 heat rate, for the flexible, maybe 5.

MR. RODGERS:

What flexibility are you talking about, other than minimum takings?

MR. SCHNITZER:

Ideally, what we would like to have is the ability to call the generator and say, increase the output by 50 megawatts. Remember, that's the flexibility that we have in our own generators a day in advance. So we don't know exactly what our load is going to be. We don't know which generators may trip. We don't know whether a weather front is going to move through, so we need to have flexible generation that can match the load.

Like, if I have to schedule generation a day in advance, or even 8 hours in advance, it diminishes the value to me of the generation. Remember, all of my generation -- because I can change the output, and we do change the output every 4 seconds. We send signals every 4 seconds.

MR WOOD:

The company whose 9 bids were all accepted, what kind of flexibility did they offer in their bids?

MR. SCHNITZER:

Chairman, I really don't -- I'm not that familiar with each one of them, but I believe that theirs didn't harbor a lot of flexibility. They just had a better price.

MR. WOOD:

Has there been an interest in procurement for short-term, private --

MR. SCHNITZER:

Oh, we did. Aside from the weekly market, we have the long-term RFP. We have monthly purchases. We go weekly. We go daily. We go part of the day, and then we go hourly. We buy probably as much energy daily as we do weekly.

MR. WOOD:

I --

MR. SCHNITZER:

Yes, sir.

MR. WOOD:

And if you asked again --

MR. SCHNITZER:

That's correct. We don't know exactly where the QFs are going to put this. We have a pretty good idea. That amount could vary, which is another reason we need flexible generation.

On Page 25, I'd like to address this idea. Generally, I would discuss our generation. They assign it a heat rate of 10,000. The reason why we do that -- why we run our own generation instead of buying from IPPs that offer low heat rates. That heat rate is not the only factor considered. Flexibility is often the key combination and one that is overlooked in simplistic comparison. Why would you run that generator as opposed to this one? The role a particular source will play in Entergy's findings will determine what is the more important considerations. Whether we're trying to fill a base-load energy requirement or whether we're trying to fill a reserve requirement is going to determine what are the important factors as to whether an offer is attractive.

I'd like to spend a few minutes walking through an example. I think this will provide great insight into -- this is a very simplistic example, but assume that Entergy finds itself 400 megawatts shy of operating reserves during peak hours. In other words, we must acquire the ability to turn up generation within a 20-minute time period by 400 megawatts. And that's a requirement that we have to meet every day. Now, what we're doing here, if you're just looking at that one requirement, we have two choices. One, is we can either operate one of our units, a 400-megawatt unit that we can turn down to 50 megawatts and then operate at 50 megawatts with the ability to turn up to 400 if we need it. Or, we can buy from two IPPs that are each offering us 200 megawatts of flexibility. But they give us a requirement that we have to take 200 all the time for the ability to increase by 200. Again, we haven't gotten many of those bids, but, just as a hypothetical, we would use that as an example.

Now, we go to the next slide on the cost differential. The option 1 is operating our own generator. The minimum take is 50 megawatts for 24 hours. We cannot turn these units on and off quite as effectively as the IPPs can do. We have to run ours for 24 hours. And the heat rate, when it's operating at such a low level, is fairly inefficient. It's 15,000 BTU's per kilowatt hour. Now, if we have to turn it up, then our increment on heat rate is not so bad. It's only about 1000.

Now, option 2. They're offering us purchases of up to 800-megawatt maximum. We have to take the 400 megawatts, but generally, they only make us take it for 16 hours because they can turn their unit on and off every hour. Their heat rate, at minimum, is 8000, and their incremental heat rate is 8800. For this analysis, the incremental heat rate is more meaningful because all we're looking for is to have the ability to turn up. We don't have any plans to turn up.

We have to look at what the impact is of taking a must-take energy from both those resources. For our off-peak 8-hour block purchase, we could make it at $20, and on our peak purchases, we could make it up to $40. Delivery of natural gas cost is $6.

On the next slide, this is just a graphic illustration of the flexibility that we require; 400 megawatts during peak hours. Now, for option 1, you'll see that we have to insert 50 megawatts around the clock, and we have to forego, then, purchasing 50 megawatts during off-peak and 50 megawatts during on-peak at attractive prices in order to accept that minimum take. So the cost incurred -- I'm on Slide 30 -- to operate the 50-megawatt unit for 24 hours is 1200 megawatts. That's $90 a megawatt hour is what we are paying for that energy, which is very expensive energy, and we have to buy 1200 megawatts of it. So our cost is $108,000 for that minimum run on our unit.

Now, we don't have to buy those cheaper blocks of on-peak and off-peak energy, and I'll avoid the math and just say that the total cost avoided there is $40,000. So in other words, we're replacing 40,000 worth of energy with $108,000 worth of energy, so our cost is $68,000.

Now, to take the IPP purchases, we have to run a 200-megawatt minimum for the 400 megawatts of generation during the on-peak hours, so our opportunity lost is the ability to purchase 400 megawatts of on-peak energy at that $40 price. So the cost incurred here is on the north side of 32 is a total energy of 6400 megawatt hours. The energy cost at 8800 heat rate times the $6 is $52. The 52 is much cheaper that the $90, but we have to buy a lot more of it. So the total cost to operate the unit is $337,000. Now, the cost avoided is the 400 megawatts for the 16-hour period at the $40 price at 250,000. So the net cost minimum is $81,000. So option 1 is the lower cost option, and it's because of that swing.

Now, turn to the next slide. You'll kind of appreciate why it's difficult for us to provide feedback on -- the prior example illustrated that a very simple economic analysis process would take two hours, and the IPPs were not the economical choice. However, the IPPs would have been the lower cost option if gas was 5.50 instead of 6. It would have been the lower cost option if the on-peak energy blocks were 43 instead of 40. It would have been the lower cost option if it would have offered a minimum take of 170 megawatts instead of 200. It would have been the lower cost option if they had offered 8400 instead of 8800. And remember, this is a very simplified example where we only looked at the need of flexible energy. A detailed analysis, the type that we do every day, every week, will consider the total load, total energy requirements, plus, reserves, transmission constraints, load restraints; all of those things. But this is just a -- one small example of why there are occasions that we run out of generators even though they are less efficient than IPPs. That covers -- I'm sorry I had to go through it so quickly. That kind of covers what we have done so far on the weekly market.

Then coming out of the technical conference, the key thing is, I think I know that generators are aware of how important flexibility is. They've made us aware that they would like us to consider this a recallable product, and at the technical conference, to work with them regarding the specification for that product for them to review. So we hope to have something, a new product, introduced by the first of the year.

I'll now turn it over to Ken Turner to talk about the WPP.

MR. TURNER:

Good morning. My name is Ken Turner. I'm the director of weekly operations for Entergy, and I have just a few slides to go over related to the proposed weekly procurement process.

Okay. First, I want to contrast what John was describing as the current process. Currently, we are in a -- what's being proposed is part of an ICT proposal, WPP. The current process evaluates offers one at a time. That's all the ability that they have. The important part of that is that even after they have evaluated the offers, and even after they have made their selections, they still have to request transmission service separate from the decision to procure it.

Under the proposed process, what we will be doing is a simultaneous authorization. We will receive IPP offered to the individual participating network customers. Our models will have the costs of the existing network resources. We will also harbor the authorization of our OPP, the definition and the description of the transmission system so we will know how much transmission has to be available. Coming out of this authorization will be a least cost weekly line-up.

Now, because we are -- as I described it at the technical conference in New Orleans -- once we decide that a particular offer is to be accepted, then that will displace an existing network reserve. So there is really no need at that point to request additional transmission service. We're swapping out an existing network resource for a new selected vehicle.

This new process offers the potential to have additional substitution by the IPPs and the existing network resources. However, I need to point out that the degree of substitution -- the success of this substitution is going to depend largely on the level and nature that we lack today.

MR. WOOD:

Let me go back for a second, Ken.

John, are there any non-secondary --

MR. HURSTELL:

Yes, there are. I don't see that -- every generator is going to be by their own air current, and they can reflect the value of it. And it could strengthen their energy bid. They're going to choose to only bid during the time that they think they think they can beat the highest price.

MR. WOOD:

So how does that effect your units over there that are not ready to be used? How do we reflect the --

MR. HURSTELL:

Particularly, the -- generally, they can only operate a certain number of hours a year, so we're just not going to make them available and treat it as being unbillable during the winter, fall and spring months and reserve its availability during the peak periods, just like we would hyper-resources that we only get so many hours out of the year. We wouldn't want to make it available during the sub-peak.

It'll affect what resources we make available to compete in the WPP. If we have a generator that we can only operate for 10 percent of the time -- I can't think of one right now -- but we're just not going to make it available to compete in the WPP during the spring and fall. We're going to save it for the summer months.

MR. WOOD:

Thinking back to the other markets that I understand -- there's not a single --

MR. HURSTELL:

It pays the bill.

MR. WOOD:

How much information on the last slide comes out after you go through procurement? How much information is out there to let the person know? Is that information made available?

MR. HURSTELL:

No, it's not.

First of all, there is no really winning bid. There is no dollar-per-megawatt-hour bid. We talk about all sorts of different parameters, and the winning bidders know what they are going to get paid. The losing bidders are not provided with that information.

MR. WOOD:

Sorry, Ken.

MR. RODGERS:

As long as we are on the same subject, I thought you said earlier when you pointed to Company "N" that the reason they won their nine bids was that they offered flexibility in the bids. But then I thought you said later that they won because they had a low-cost bid.

MR. HURSTELL:

No. If I said that, I misspoke. I'm not absolutely certain. It's just because I don't follow the specific bids individually. I believe that that part is flexible products, a product offered at a very low heat rate. I guess that's the point is that if someone wants to sell us a block of power, and if they offer us a price low enough, we'll take that. We're going to take five blocks of power. We'll take 24-hour blocks. We'll take 4-hour blocks. It's just that each block is going to be competing against different resources. And if you offer us a price low enough, we're going to take it.

MR. ROGERS:

But one thing that strikes me about your slide is how variable the rate is. Even though it's been 4 percent to 100 percent, and actually begs the question as to why is that level of disparity. And one company, the company that offered the most bids of the 9 -- oh, the second one -- they bid 162 times and only 15 were accepted.

Do you know why those few were accepted?

MR. HURSTELL:

The simple answer is because they didn't provide good offers, but I think --

MR. ROGERS:

Were they good in any different respects?

MR. HURSTELL:

Well, that's right. We evaluate every one of them. They might offer us -- they hear us say we want flexibility, so they offer us flexibility. But they put huge premiums on that because they believe that that's what it's worth and fail to consider the economics of flexibility like we just went through. I'm sure that some of them have never stepped through the economics as we just went through a few minutes ago.

MR. WOOD:

Well, Company "N" may be flexible, but it is never accepted.

MR. HURSTELL:

That's right, because they offered us very low prices. Remember, there is a market outside of what we do. You can trade power. You can give it to Entergy. You can deny power to Entergy. It's not like they have no idea as to what the market conditions are. And I think Company "N" has looked at what the market is for a flat block of power and compete against that and sold power in the weekly market.

MR. RODGERS:

Well, Company "I," when 90 percent of their offers are rejected, do they -- are they informed why they were rejected? Was it flexibility? Was it too high-cost?

MR. HURSTELL:

Well, that's why I went through the example. It's hard for us to say why.

I mean, those 162 offers may have been in a 10-week period. They may have offered 16 different bids in a week, and we may have taken one of them. We may have been only able to take one of them. Or it might have been -- I'm sure there were multiple bids, so some of these generators may give us five different bids, trying different variations to see -- they don't know which one is going to work. We don't know which one is going to work until we put it in the production costing model. So we just take the information they give us and see how it comes out.

When it comes out as rejected, we don't know why it didn't do as well as something else. We just look at the total cost and say, the production costing model says you're not as attractive as this other offer.

MR. RODGERS:

When they are told their offer is not accepted, do they get any information on the offers that were accepted so they could then figure out why theirs were not?

MR. HURSTELL:

There's two general thoughts on that. One is that if we release the details, we would then be providing information so that people can lower their bids and be more competitive. What may be equally as valid, and we think is quite more valid, is release of the information is going to provide information to those that bid low to increase their bids.

You know, for example, I don't know if one week's worth of data, and we accepted -- we took heat rates and arranged them from 8.2 to 8.7. If we released that we bought power at an 8.7 heat rate -- you're right that there may be some that bid 9.2 or 9.4 that may come down. They're going to come down to the 8.7, but I think equally as valid is the concern that the parties that were bidding the 8.3 are going to start bidding 8.7.

I think the argument can be made on both sides. It's just that right now we feel like providing that information is going to provide more information and is going to provide more help to generators trying to increase their margins than it is to generators that are trying to increase their sales.

MR. WOOD:

Aren't these figures reviewed, though, for the --

MR. HURSTELL:

Yes, definitely. Everything we do is reviewed.

MR. WOOD:

And so, won't that information come out later?

MR. HURSTELL:

I don't think so because usually when we file cases, things are aggregated, and then any specific transactions are usually filed in the confidentiality agreements.

Mr. Chairman, I'm not sure, maybe, what and when may become available publicly. In a year or two years, sometimes -- like in Louisiana right now, we're reviewing purchases made back in 1989. Even if it does come up, then I'm not sure.

MR. WOOD:

Mike, I know you participated in other markets across the country. You purchased -- for a number of reasons over the years, we've generally come to the conclusion that market prices tend to result in the overall cost to the customer. Why does that sound applicable here?

MR. SCHNITZER:

There's a couple of questions there.

The issue of payment bid versus market cleared prices is one which Entergy has been in conversation with all its regulators at this time. And you know in earlier wholesale market development efforts, the company supported so-called danger markets which would have the characteristics of a market cleared price, occasional price markets. But there's discomfort here and not yet support for LMP or something close to it.

So this proposal, the one that's before you in the proposed WPP, let's not take that one on. Let's do bid pricing. But where you go -- where the Commission has gone to market clearing pricing in our markets, it's part of the package of things. It's part of the package of the -- markets. Typically, there's a research advocacy requirement which carries with it an obligation of generation scheduling a bid every day and be in the market every day. It carries with it a set of market mantra and mitigation activities.

Where the Commission has embarked on market clearing prices kind of structures, they are part of the whole process which, to our knowledge, are not -- have not been, and are not capable of, being implemented, short of the whole RTO-type market. And in that context as Entergy has supported them in a number of contexts, most recently

CTRANS. That would be fine and there would be disclosure. There would be market clearing prices and there would be disclosure of those prices on a temporary basis. But that's a whole different package of attributes than what we're able to work with here.

MR. WOOD:

You know, though, the PJM. But long before they had an RTO, they had economic dispatch that was owned by numerous people. But they'd have -- I don't think they were a complicated structure as we have here. They were more frequent. I wonder why something like that--

MR. SCHNITZER:

Does your question about earlier PJMs go back to the split savings arrangements in a tight pool dispatch, or are you talking about the intermediate step where they had --

MR. WOOD:

You've been around longer than I have, so -- well, take both of them and tell me why there's not an easier way to get there than --

MR. SCHNITZER:

Well, the other predecessor arrangements to major markets and the tight pools were separate corporate entities, basically. And the question was, how could they centralize dispatch and share the benefits? That required the price to affect a number of things like exchanging of the energy into more interchangeable energy. It also required all of them to establish a set of rules about how do they know that no one is leaning on anybody else. So even those structures had those kind of rules. But they were principally arrangements for getting more economies to scale on an equal -- back in those days, it was a 10,000- or a 12,000-megawatt market in its entirety, and it's grown to 20,000 megawatts at this point. I mean Entergy is 9000 megawatts, so it's a different scale in the early days.

Aggregated together, they're as big as Entergy is. But the issue of pricing was basically coming out of a set of pooled resources and pricing interchange, and this is a different arrangement. It's one company's procurement on its behalf and another company, if they want, can have another customer on their own behalf. It's not quite the same as trying to achieve a centralized dispatch among integrated players, which is what those -- we don't have that issue, or that problem is not the principle that we're trying to address here. It's trying to integrate new resources that are not owned by an integrated player.

I don't know if that's a helpful response.

MS. HOCHSTETTER:

Mike, I don't know if this is an appropriate question for you or someone else, but this follows up on Chairman Wood's question.

Once, Southwest Power pulled a real-time spot energy balancing market. It established one and then put it in place. Seems to me that that might be an alternative option or, perhaps, a supplemental opportunity to the WPP to look at shorter-term economic purchases. That would establish a larger cut in price as the Chairman indicated, and, obviously, we would have a lot of transparency and would be right in your region.

So is that a possibility that you guys would consider participating in, either as an alternative or a supplement to the WPP?

MR. SCHNITZER:

That will open up a big can of worms. Just let me say we put aside other STP-related issues of transmission pricing and the like. We're just talking about this piece.

MS. HOCHSTETTER:

I'm not talking about y'all being a member of. I'm just talking about your participation.

MR. SCHNITZER:

Fair enough. We're talking just about that. I think the part of your question that said supplements may be a possibility. I'm not an expert on that STP balancing, but in terms of replacement, I think my answer would be, no, because we discussed it in New Orleans and at previous times that the big opportunity for displacing better integrated merchants comes at the commitment stage. And that's why we're talking about the procurement is that -- and again, to get us oriented here -- remembering about that total energy pie we talked about in New Orleans.

We're down now to the 20 percent of the total retail energy requirements for Entergy's customers on a annual basis that are currently mapped with these oil and gas units that I'm talking about. Is there an opportunity to displace that? What are those units and how are they committed right now? How can they be displaced? And the answer is that those units typically have 24- to 48-hour start-up times. They have two- or three-day minimum cool-down periods before they can be re-connected. And Entergy's current practice is to basically commit or not commit those units for a five-day period. And once that decision is made, we're going to take it on-line and leave it on-line until Friday, at least, and see come the weekend whether we can take it off or not. And all of the balancing markets are only going to be on margin and Entergy through economy purchases right now. I think John would tell you it takes pretty full advantage of short-term markets.

But if we're going to do more displacement of those commitments, we have to have something that can be compared apple to apple against that unit and in John's example in the operating reserves. If you want to meet operating reserves, we've got a unit that's already on-line. We can divide that, or we might substitute somebody else. We don't do that an hour in advance. That unit is going to be committed at 50 megawatts, in his example, for the week or for the period, or it's not. And that decision, once it's made, can't be reversed for about four days; two or three days to cool down and 24 to 48 hours to come back up. And so, that's why the weekly focus is on this particular effort because that's the opportunity we're trying to further realize is the commitment opportunity. It would not help the commitment displacement issue, which is where there's some more leverage and more dollars.

MR. HURSTELL:

It's just to say a little more succinctly that we're not going to put ourselves in that position where we have to buy energy in the short term to keep the lights on to our customers. We can't count on a balancing pool to be there. We have to be prepared to put and have the units committed to supply.

I guess, getting back to your question -- the Chairman's question on releasing information. It was pointed out to me that the sellers -- we don't release information, but the sellers have to make their quarterly filings where they have to release information on all their sales. So all the information is going to be available on a quarterly basis.

And finally at the technical conferences, this issue came up on the leasing commission, and we had two parties that were routinely winning -- they did a good -- frequent winning bidders. They expressed the desire for us not to release the information. They felt like they had invested a lot of time and effort to put forth the right information so we could write bids that we can take to Entergy. And they were reluctant for us to just hand it over to everyone else.

MR. RODGERS:

Can I just mention, though, those quarterly reports that you refer to, John? They don't provide the kinds of details that would help someone who was losing know exactly why they lost the bid.

MR. HURSTELL:

That's right.

MR. HURSTELL:

That's right, Steve. And what I tried to show in my example is that unless you provided the detailed bid, every part of the detailed bid -- what the heat rate was, what the gas basic adder was, what the flexibility was -- unless you provide all of those, it's not going to be meaningful information. And the more detail you provide, again, you get to that two-headed coin. One side says that if you release the information, you can help those who didn't win to put in better prices, but the flip side is that you can help those who did win to put in higher prices.

MR. RODGERS:

I'd like to follow up on that for just a minute.

If you go back to your chart on Slide 6 from your presentation, if you look at the four largest bidders in terms of number of offers that were made, it looks like Companies "C," "E," "H" and "I" -- for those four that have far more bids than anybody else did, not one of them had more than 22 percent of their bids selected. So it just seems to me like there would be some benefit to Entergy and its ratepayer if there would be a way for Entergy to provide more transparency, provide more information, informing bidders of how they need to be more flexible, specifically in what price has won on a timely basis. It seems to me that that would be to your benefit.

MR. HURSTELL:

Well, again, it gets back to -- it's not like we know what price would have won. We use this production costing model, and if you remember, we talked about it. It's how much time it would take for us to go back and look at every offer and do the detailed analysis as to what tweaks you had to make to your offer in order to be a successful bidder. And what I would tell you is if you look at Company "I" who had 162 offers, and they only had 15 taken. That's the key thing. It's only 15 weeks that they were accepted.

If we tell them every week, lower the heat rate, provide more flexibility, lower the gas prices, and if they haven't gotten it yet, if they haven't been able to lower the heat rate enough after putting in 162 bids, then us telling them to lower your heat rate from 9.2 to 8.9 is not going to help them. They're at 9.2 heat rate, and we say lower your heat rate, and if they come back with a 9.2 heat rate, what good is it going to do to tell them a specific number?

We are still telling them to lower the heat rate and provide more flexibility, and that is giving them the direction they need to go in. Those are the things they need to focus on. And to be very candid with you, I just think some of them are just reluctant to provide us that flexibility because they think they can do better in the daily market. Remember, we're asking them to commit for a week. When they commit for a week, they miss out on the chance of a daily spike in prices, and that's the bet they're making. They may be very happy that they don't get some of our bids. I don't know. It sure looks like they're not being aggressive bidders.

MR. KELLIHEE:

John, if I could follow up on Steve's question.

It strikes me that transparency is of value to either Entergy or to the bidders. You could take what is a variable and make it fixed. You can take flexibility, and instead of having a kind of a signal, you could break it into a couple of products with range and flexibility. And then you could release information after the fact on which those products you accepted and what the effective heat rate was for those products.

Have you considered something like that?

MR. SCHNITZER:

Yes, Joe, as a matter of fact. You painted the perfect -- that's exactly what the recallable product that we talked about is. We're going to develop a production that says you have to offer this amount of flexibility. And I think we said 50 percent because we try to make it something they will bid on, Numbers 200 to 400 or 100 to

200. And there are definite parameters that you have to live by, and the only thing that you can bid is a heat rate and a gas business so that way, we will have a standard -- one standard product that they can bid on.

But the problem with that is, remember, there's no Holy Grail of what products are going to work at what price. As I said, if you offer us a 16-hour block of power with a 6000 heat rate, we're going to take that product. If you offer us a 16-hour block of power with a 9000 heat rate, we're not going to take it. But if you offer us a four-hour block of power across the peak of the day at a 9000 heat rate, we might take that.

So the last thing we want is for everybody to be bidding the same thing. We need the diversity in product because we need the diversity in products.

MR. KELLIHEE:

We have talked about quantity disclosure as being something that may provide feedback that says there are transactions being done in the marketplace, and it may give them some comfort that we are doing something. And they can see how quantity is changing. We are hoping to -- in considering that, that's one of the things that we said we would talk about with a recallable product.

MR. RODGERS:

Mr. Schnitzer, if we could go back to something you were discussing a minute ago on the STP balancing market. I understand you say that the market is an hourly market and you need research that generally, for most of your needs, that are longer time frames. So as a direct Entergy participant, it's not an ideal fit for most of your needs. But does it provide other opportunities they would not have today, such as traders, who would say, I'll commit to sell to you 16 hours for five days at this price, and I'll buy that in the balancing market and take the upside if the price is lower and take the risk if the price is higher? Do other people fill the gap between Entergy and the balancing market and have the opportunity to give more flexible products that way?

MR. SCHNITZER:

What you're talking about is getting other people to service and then -- well, we buy energy every hour on an hourly basis. I would say most hours, we buy energy. There may already be people doing that right now. We buy a 16-hour block of power and hedging their bet that they're going to be able to sell it to us every hour. So we're doing our part, and we look to buy every hour.

MR. RODGERS:

I agree. People can do that now. I'm wondering that in an organized market like the STP balancing market gives those intermediaries a more assured opportunity of being able to fulfill their commitments they may have to Entergy.

MR. SCHNITZER:

With as much generation in our area right now, including the QF generation, anybody that wants to buy a coverage, you just have to offer the right price and you're assured you get power. You're not sure of the price. I don't think the balancing pool creates -- the balancing pool would create anything new.

MR. RODGERS:

But I think that -- the questioned issue aside, and the reason we're here with this proposal is basically an assessment of where the money is. Where is the opportunity? And the opportunity appears to be -- there's oil and gas generation, the heat rates that John described, owned by Entergy running on a weekly basis and collectively produces 20 percent of the annual energy requirements for Entergy's retail customers.

And the question is: Is there a way to reduce the cost? The rest is coal and nuclear and QF purchases that are already being made with all the different kinds that John is describing. So that's the piece that's left. As it happens, the average capacity factor for that remaining piece is low. It's 20 to 30 percent a week. Those units that basically run for the purpose that we're describing, they go up and down every day. That's why we're focusing on this flexibility. Everything else has been bought. The piece -- and we can buy better. We can buy cheaper, maybe, some other ways, but the piece that is yet to be, perhaps, wholly tapped is this remaining piece, and it has the characteristic. And it goes up and down every day.

If we're going to get some of that remaining share of the energy pie that we talked about in New Orleans, it's only going to be if we get something there that would cause us not to commit one of our existing units that we would then run at 20, 25 percent capacity. And anything else may provide other types of evidence, but if you buck the proposition or you agree with the proposition, the biggest remaining opportunity is with respect to that 200 percent. And you better find a way to find resources that will go up and down every day and will have the lowest possible minimum block for the ability to go up and down every day. And that's what this weekly procurement is currently trying to do, what the weekly RFP process is trying to do and what the weekly FP process is designed to try and do better. That's what it's about.

MR. WOOD:

So what the recallable product is is the attempt to not have something that is so black or white for the market, for the non-Entergy generation, so that they, under some conditions, could back out and play in the hourly market.

MR. SCHNITZER:

Yes. In financial terms, what Entergy's existing plants are are options. They're callers because you have the right, but not the obligation, to run, but it's at specific prices. And so, you need to buy options from somebody else to replace them. But once they commit that strike price to you, if the market runs way up, they've lost the upside. And so, they're saying I need to get paid more than you're willing to pay me for the option. And we're saying, we can't pay any more than we're willing than that for the option because our units have that option. So if you want to sell me a less valuable option, I'll look at that. And that's the recallable product, a less valuable option.

MR. HURSTELL:

That's a part of -- the market participants asked us to develop a clear method to do that.

MR. WOOD:

That's in your meeting here, or the meeting here, or your meeting in New Orleans?

MR. HURSTELL:

I'm not sure exactly where, but there's going to be a meeting in November. That's right.

MR. WOOD:

Speaking of New Orleans, I'm going to divert my question, then get back to this since Louisiana's not here.

What is going on with that commission in regard to commission studies or generator shutdowns?

MR. SCHNITZER:

The pirate study?

MR. WOOD:

Correct.

MS. DESPEAUX:

Yes. My understanding is that the Louisiana commission staff is working on the study and that they retained some advisors to help them on the study. And I'm not sure exactly when it is expected to be released.

MR. WOOD:

What would a possible format for that study's results be?

MS. DESPEAUX:

I can't --

MR. WOOD:

These five plants should be replaced by these five plants?

MS. DESPEAUX:

I'm not sure what the results will be.

MR. WOOD:

Then, I guess, more of a legal question is with regard to how the cost of this 20 percent slice are shared within the five jurisdictions. How does that work?

MR. SCHNITZER:

That basically takes place according to the agency system premium.

MR. WOOD:

Which is the pro rata share?

MR. SCHNITZER:

No. It's the way the accounting's done that's on an hourly basis. Each company's load and generation is totaled up and companies that are short are deemed to be purchasers who can exchange energy. And companies that are long are deemed to be putting energy into the exchange inner tube, and it's all transacting costs. And the rules about which resource -- which energy goes into the pool and pricing and all that are pursuant to --

MR. HURSTELL:

The first step that happens is given it pro rata share on every purchase so that then, whether the purchase is economic for a particular company, will determine whether or not that purchase goes to the exchange or something else goes to the exchange. We make a purchase that --

MR. WOOD:

The purchasing is done in the weekly RFP with current prices?

MR. HURSTELL:

That's correct. Every purchase is a joint account purchase. For example, Mississippi is going to get its share of every purchase, and then every hour, it's going to be determined whether Mississippi is long or short. If Mississippi is short, then obviously, they need everything they have and it can be exchanged. But if they're long, then it's going to look and see what the most expensive source on the Mississippi system is, and if that's this purchase, then this purchase goes to the exchange.

But the first step is that every operating company get its shot at these purchases.

MR. SCHNITZER:

But for the plants themselves that are currently generating those 18 and that 20 percent, they are owned by whatever operating company owns them, and so they show up in the account of the operating company that owns them.

MR. WOOD:

Does the long/short company --

MR. RODGERS:

If we could, Ken's been very patient over here undergoing an endurance record for how long he can stand still, so you're doing a great job over there, Ken. We'll get back to you in about half an hour.

Seriously though, Ken, if you could, go ahead and finish your presentation on the proposed WPP process, nd then we will take a short break for about 10 minutes and come back with some responses or perspectives.

MR. TURNER:

It won't take me very long.

One of the last things I said about 30 minutes ago is that we feel like the proposed WPP gives the potential for more substitution of IPPs. What that does is it reduces the cost for the local customers that are participating in the process. It also allows IPPs to sell more power on our system. Another benefit of the proposed WPP is the potential for the additional sale of more transmission service through dispatch. I'm not going to get into the re-dispatch issues again. I covered those in the last technical conference.

The additional sell of transmission service, again, benefits network customers and it allows IPPs to supplement power off our system. This proposed WPP also maximizes the transmission system on a weekly basis, and one of the issues that keeps coming up is AFCs and what impact AFCs has on WPP or the WPP on AFCs. AFCs are not going to affect weekly transmission service through the WPP, unlike the process that John talked about in the current weekly RFP process. Once the bids are selected in that process, they still have to apply for transmission service because we are doing simultaneous optimization. And we're actually substituting an existing network resource or selected bid, then there's no reason for the AFCs to get additional transmission service granted.

Once the WPP has selected the bids and gone through the granting of the additional port-to-port service, that then results in the final rung to form the basis of the AFC process from that point forward, so all new requests for transmission service will reflect the results of this simultaneous authorization.

And the final benefit of the WPP is that, unlike the current process, there will be an independent oversight proposed by the ITT of this WPP process. We feel like that will give greater comfort to our regulators. We see that as a benefit of this process.

The final slide really has been covered by some of the questions that Michael was asked, but I just want to point out that the WPP is a procurement process. As Michael described, and he can describe it in a lot better detail than I can, markets would require all the selected resources to be paid with market clearing prices. There are other attributes of the market that Michael covered, such as ICAP. Markets would also require a very complex settlement process.

The next bullet, WPP is not a pooling arrangement. What I mean by that is that the Entergy generation is not for sale to other customers through the WPP at cost. And an important part of this WPP proposal that I covered in quite a bit of detail at the technical conference in New Orleans is that all participating customers must serve their own network resources and/or IPP offers that they bring to the process. They have to bring enough of their own resources, plus offers.

Mr. Chairman, that's all I have.

MS HOCHSTETTER:

Ken, before you leave, I have a quick question.

I know you'd really like to sit down, but I seem to recall back at the tech conference in New Orleans that one of the restraints, or caveat, with the WPP was available transmission capacity in the sense that where you have a must-run unit because of existing constraints, or it had a capacity that was a knock-out of the caveat on participating in WPP. I guess I'm trying to rectify your optimization comments with what I understood in New

Orleans.

You've expressed, in addition to all of this, that there could be transmission constraints that preclude some offers from being accepted as opposed to it just being a matter of displacing one of your 15 company-owned units with a unit on the market. And so, can you clarify that? And I have a follow-up question after that.

MR. TURNER:

Let me try it this way. If I misled you, I apologize, but the simultaneous authorization will have the transmission system model as per this. All constraints will be modeled. We'll know what the constraints are.

MS HOCHSTETTER:

This is my last question.

What if you have some offers that can't be accepted because of transmission constraints? Is there any way that your computer process can capture all of the economic offers that would have been more optimal than your own generation that could not be accepted but for XYZ and transmission constraints? It seems like after some period of time that if you tracked all that, you would be able to identify, from a transmission planning standpoint, where you need to put in some fix-its, if you will. Are you tracking that so you can put economic transmission bugs to take advantage of these more economical generation offers?

MR. TURNER:

Michael, you help me out here with this. I believe that we will have that information.

MS. HOCHSTETTER:

The system will track that?

MR. SCHNITZER:

Yes. The proposed WPP, one of the by-products, if you will, of the outputs, it will tell you if there were constraints that were binding that kept you from doing something that you wanted to do and how much that costs you on the margin. And that will be available week in and week out, and those constraints will be of all kinds. It could be a transmission limit and say, oh, that transmission limit was binding, and in technical terms, a shadow price. It tells you how much it would be worth if you had more capacity on that constraint.

Similarly, you'd have to have so much flexibility because you'd have to able to absorb a 3000 kilowatt QF foot. It will tell you how much that costs you. So all kinds of constraints will be represented. And if they're binding, they may not be, but if they actually prevent you from doing something more economic, the penalties associated with that will be able to be collected to track, as you suggested, on a weekly basis. And over time, you could say, yep, there is a trim there and this is what it would be worth to do something about that. You're exactly right.

MR. ROGERS:

If there is no other questions, why don't we go ahead and take a 10-minute break? I wanted to mention that there are some refreshments that are available downstairs in the atrium, which is one floor below us. Please join us down there.

(Whereupon a break was taken)

MR. WOOD:

Let's go ahead and take our seats, please, so we can get started here. I'm going to bogart a little bit of time from the afternoon panel, and say we're going to try to do lunch around 12:20 or so. So why don't we spend the next 50 minutes having a round-table?

We've got here, I believe, some folks that we had at our last hearing in New Orleans. We have Mr. Adams from NRG; Mr. Marrone from Occidental is back; Ms. Mackey. Mr. Carraway in en route from the Mississippi Delta. Why don't we --

MR. RODGERS:

In just a minute, I'm going to introduce someone from Louisiana that has joined us, but we'll get a status report on what's going on there. But in the meantime, why don't we have Lynne Mackey from InterGen go ahead and tell us her thoughts on where we're at.

MS MACKEY:

Hi, I'm Lynne Mackey, as Steve said, from InterGen.

I would say as a general statement, we still have some concerns regarding how Entergy arrives at its decision to run its own unit versus the other units offered by the market or the IPPs. Also, not just how it runs its own units versus, for example, our Cottonwood plant, but how does Cottonwood get judged against the other IPP's?

On different occasions, Entergy has made it clear that the IPPs are really competing against each other as opposed to competing for a big chunk of the Entergy load that, we heard today again, is about 20 percent of what's left. So that data and information would still be very helpful to us, and I think that is an over-reaching statement we heard that Entergy is concerned that there are people who don't want some of this information published, some are contributors to the WPP process. And what we'd like to propose is that they hear what our main concerns are. They heard the Commission and the state regulators interest in the transparency issue, and I think it would be helpful, at this point, if Entergy took that information and came up themselves with some proposal for transparency that could be incorporated into this WPP process that we could all comment on. So if there are people who are against it or there are aspects of it that certain parties aren't enthusiastic about supporting, then we can all entertain it through that type of process.

I think we feel like we've communicated on a one-on-one basis versus an individual IPP basis our general issues. We think that at this point, that Entergy coming up with a proposal would be the productive next step instead of us continuing to throw things out there and having them discarded, or considered and then discarded. It's time to come back from the other angle.

One other thing I'd like to say from the last technical conference that -- as far as the IPPs go, we've been, really, very resource-constrained with some of the other dockets that are out there that we're working on, and I have not been able to get the generators together to sit down and hash this out and talk about this exact type of information. And that was one of the comments that, back as I was trying to talk on the phone with the InterGen generator, which is why don't we put this back on Entergy and say the people who want to sell you power think it's important. The regulators seem to think that it's a relevant issue to be raised. Maybe it's time for Entergy to respond to those concerns and actual propose something. So that's my first over-arching comment I would like to make.

MR. RODGERS:

Did you explain to us what the nature of your concern was among the generators that did not want more transparency? What was your reason for that?

MS. MACKEY:

Thank you for bringing that up, actually. One of the IPPs that I spoke to -- the IPPs in general, and this is not a consensus statement, as I said, but the essence that I get from the IPPs is that we have so much more to lose by not having price signals and transparency that anything that was potentially lost by having a bid information review is minuscule. So it pales in comparison to losing on a weekly basis on a bigger scale.

The two voices that I heard at the one technical conference in D.C. -- they claimed that that was their -- they didn't want that revealed, or any of that information, because they felt like they had prepared competitive bids. That was kind of the essence that I got. I don't want to speak for them.

What I want to say is those two at that

specific meeting actually were there representing an InterGen project and functions in a trading-type of position for us. I'm sure they do it on behalf of other people as well, so I'm not saying they're not responding to Entergy RFPs on behalf of others -- maybe the wrong units or something else. But it wasn't -- well, I can say that I can withdraw the 1200 megawatts that he was representing from InterGen's perspective and that person should be carved out, at least for the 1200 megawatts that they represent us for. If we ask him again, he'd probably say no, at least as far as our megawatts go.

Maybe they have less to lose. I don't know. That's speculation on my part. But the other thing that I would like to at least just bring up right away was that Mr. Self said that flexibility is a priority, and he gave an example on his page 26. He was evaluating purchasing flexible energy from an IPP versus its own unit, and then, correct me if I'm wrong, but I also thought I heard that that flexibility on a daily basis is how the decisions will be made. If Entergy did buy that product, let's say it was clearly cheaper, that they would want the ability to turn that unit up or down within whatever range he had purchased. But this seems to go directly against, and I think that maybe it's just confusion, I'm not sure, against the requirement in the Gold Dust filing that we have to submit start-up and shut-down schedules by 8:00 the day ahead. So come January 1, we have to provide start-up and shut-down schedules by 8:00 a.m. the day before. So how could this jibe, and how is not in conflict with the procurement goal of flexibility?

MR. HURSTELL:

When you specify the minimum in this example, the minimum is 200 megawatts, then you will know a week in advance that every day that you're going to start at 6:00 a.m. and you're going to go until 10:00 p.m., so you can submit your start-up schedule before and you can -- there's no uncertainty of when you need to start. The uncertainty is how much you're going to take.

As we said before, it's consistent with the GRS and the GIA. You can put in 20 minutes or 10 minutes, so we can tell you 10 minutes from now, move from 200 to 400. And if your ramping ability capability isn't such that you can provide that, you can only provide 100 megawatts, then that's the ramping that you can provide. The scenario that I laid out wouldn't require you to incur any GRS charges.

MS MACKEY:

I think that maybe we can just take that off-line. I am not confident that the goal of flexibility and the GRS as it's designed, doesn't limit our ability to provide you the product that you want. So maybe we can just take that off-line.

MR. HURSTELL:

Before you say take it off-line, let me at least have a shot at saying that I think it's completely consistent, that there may be some misunderstanding, but the idea behind this is that if you put in a schedule, you will match your schedule, you will match your schedule. And if we're obligated to schedule energy from you, then we'll put in a schedule, and you match it. We will be happy to take that off-line, but I don't think that there is any consequence.

MR. WOOD:

Is that Cottonwood plant, Ms. Mackey, the one that is susceptible to become available for a real peaky nature, what you have described -- of their needs for that last 20 percent slice of their --

MS. MACKEY:

You mean, could we provide that?

MR. WOOD:

Yeah.

MS. MACKEY:

Yes.

MR. WOOD:

Is the flexibility, then, more of a financial issue, or is there an operational issue?

MS. MACKEY:

I'm sure that there are pieces of it that they would consider to be operational, but I would say that it's a blend between operational -- we have a minimum level we have to run at. And that puts us into probably certainly not the minimum 50-megawatt category compared to our own unit. So I would say we're on both sides of that; operational and financial.

I guess kind of a related question that during those flex -- how would the GIA sell be applied to somebody who would provide you with that flexibility? Is the GIA with its hourly calculations and quantifications -- it seems to me that we do have an apple-to-oranges comparison with the GIA and GRS versus this need for flexibility. And maybe, again, it's just something that it's as a regulator person instead of the commercial person. I'm just not understanding this.

MR. HURSTELL:

Let me try to help you.

First of all, the GIA, the Generator Imbalance Agreement, applies to schedules from generators. If we enter into an agreement through the WPP, then you would be designated as a network resource. We're not obligated to schedule from a network resource so, therefore, GIA wouldn't even be applicable because there are no schedules.

MS. MACKEY:

This is what the WPP has proposed?

MR. HURSTELL:

Yes. Right now is the kind of flexibility that we've gotten so far, and the weekly RFP doesn't even approach the kind of flexibility that would cause any problems with the GIA because so long as we had to give 10 minutes' notice that we could tell you, here is what we need from you, schedule the transmission. As long as you match the schedule, there would be no GIA charges.

MS. MACKEY:

Okay. The only other feedback that I received from the other generator -- and then I'll let somebody else add their comments in -- was regarding the additional types of products that would be -- we think would be helpful for us to be able to sharpen our pencil and get you as competitive offers as possible, and those types of products and receiving feedback -- signals on those types of products. Maybe in the similar was regarding re-callable products that you're speaking about would be helpful. And that includes the shaded boxes so that it's a pre-scheduled variable amount of megawatts with a specific number of hours.

One was the weekly implied heat rate for the group of people who responded in the weekly RFP process with that type of product, or price per megawatt hour and how many megawatts were purchased, so a type of product, the number of megawatt hours bid, the number of megawatt hours. And in that case, really the average heat rate, in my mind, should incorporate any gas adder so that that becomes built-in for the purpose of transparency. So it doesn't have to be kind of an unknown variable that hangs out there.

MR. HURSTELL:

We'll look at that. We're going to have a conference in mid-November, and we will bring this issue up then as well.

MS. MACKEY:

That's all I have for now.

MR. WOOD:

Does that re-callable product -- is that something that he represented --

MS. MACKEY:

InterGen really, at this point -- and I'm just pirating, really, what our commercial guys are saying -- we really don't see the value of that product, per se, particularly because -- If the market runs up, Entergy is going to be in that market as well. And our ability to --

so that mainly when you want to recall the sustainability of that market, tries to be out there when we're ready to -- we notify Entergy that we want to recall. By the time that we actually get a sale done, the price could or could not be there. So that's one issue.

I think the other issue really is that because transmission is such an unknown, it's a re-callable product, but I don't have firm transmission -- let's say I'm a network resource -- maybe the re-callable product won't be a network resource product, but I have no idea if I'm going to be able to get transmission. So when I submit a bid for this re-callable product, I don't know if I'm actually going to be able to sell even if I recall it, because I may or may not be able to get transmission away from my plant. So there is still a lot of unknowns related to the value of that, and at this point, anyway, I think Entergy was attempting to respond to a concern, but maybe we just need more interaction to actually make it valuable to us.

MR. MARRONE:

I think it may have actually been a misunderstanding with the concern that I had raised, and maybe I didn't make my point clearly enough. But to me, there's -- we have two issues here today; we've got flexibility and the WPP. And I really don't see those as being totally related. I don't see how the WPP is going to take a look at a bid stack based on a simultaneous feasibility study of transmission and change my bidding behavior. That's really not going to change anything. I think the flexibility issue is really separate from the WPP.

Within the flexibility issue, I think it's really an issue of cost recovery versus revenue guarantee. John needs cost recovery. I want some level of revenue guarantee because flexibility -- I think Mr. Schnitzer hit the nail on the head. You don't give those away for free. It's not the smart way to do business, regardless of what your business is, to give away calls. So there's some level of reservation fee, capacity charge, opportunity cost -- call it whatever you want to call it -- that I would want to build a call option on my capacity.

If John pays me a capacity fee, he's not going to get the cost of that. If I do it all heat-rate based, he can pass it through the fuel clause. But if he pays me capacity, that's got to go through the base rates, and he's not going to get the money back. So if I do $1,000 of business, 900 is incremental fuel, and a 100 is what I want, he loses a 100 dollars. So I want the guarantee of my $100 somehow, and he wants to get paid back for it, and both of us should get it. And that's kind of the gap that's in this system.

So what can I do? Well, I'll take the $100 and roll it into some portion of my bid as a must-take. So now I'm saying, okay, John, you can have flexibility, but you've got to take 200 megawatts at this heat rate because that's got my capacity payment in it, and then you can have another 100 variable. And he sits there and says, but wait a minute, now, I've got a problem because you're giving me big chunk of must-take energy.

So there's kind of a disconnect in this system which I really think is more of a retail rate problem of how this heat could pay me some sort of a capacity payment and get insured of the recovery of my call option. I'm not giving them a free call option. I'm not giving anybody a free call option in any of my businesses. It's just not a smart way to do business. That's really the kind of key to the problem with flexibility, and WPP is not going to fix that.

MR. HOCHSTETTER:

I just want to ask a quick follow-up question, if I could.

What if one of the states, like Arkansas, had a more flexible fuel adjustment cost? Would that help or do you, in fact, because the way the system is centrally dispatched -- would every single retail jurisdiction have to allow you guys any regulatory flexibility to incorporate that assuming that the -- obviously making sure that the most economic thing happens if we allow you to recover the capacity cost and the fuel adjustment cost? This is probably a regulatory/legal question, but if you could answer that, that would be fine. But can each jurisdiction be looked at separately or does everybody have to have the same adjustment cost?

MR. HURSTELL:

I don't think everyone has the same adjustment cost right now, but let me see -- I'm not saying what Joe said was wrong, but he's not really -- what Joe has laid out is in a situation with the QFs because the QFs right now don't need a minimum take because they can sit there and put to us an economy. And what he's looking for is an option to switch from putting to us as a QF and putting to us an IPP.

Let's put aside the QFs issue for a second and talk about an IPP. An IPP -- if their going to deliver energy to us, they have to have some minimum amount of energy -- that we have to take some minimum amount. They are not in a situation where we call them up and then 20 minutes later there is going to be a unit on-line producing what we want. So the fact that they have a minimum amount means that they have to compensated for something. So whether or not they offer us a capacity price or they're collecting in a minimum take, it doesn't make any difference. The economics work out exactly the same, and if someone offers us a capacity price and a really cheap energy rate, we evaluate that the same way. We don't make a distinction the way Joe -- I'm not saying he was trying to mislead anybody, but the way he characterized it is that sometimes we reject offers that have a capacity price component, and that's just not the case. We don't worry about whether something is going to be recovered, but not literally getting the lowest-cost energy.

MR. MARRONE:

That's also a mischaracterization of my situation as a QF. I will not give anyone a free call option on my merchant capacity regardless of whether I'm the QF or not. It is bad business. It's stupid. I'm not going to do it, so I've got to get it. How do I get it? There's no place for me to put capacity down on the bid form. How do I get my money for that call option?

MR. SCHNITZER:

And there, I think, we have a difference of opinion. I did not mean to suggest in my earlier comments that merchants or QFs or anybody needed to offer free call options. They can decide what they want to charge. What

John just said was right. If a 100 dollars is what he needs for his option for that week, whether he puts in a demand charge or whether he puts it in a heat rate on the minimum block, it will be evaluated by Entergy the very same way.

So when that offer gets rejected, it's not being rejected because he's trying to recover an option premium that could have been recovered another way. It's being rejected because $100 is too much to pay for an option that is relative to what Entergy already has available to it.

MR. MARRONE:

That is a circular argument we got into at the technical conference, which is if I bid my capacity figure in and I don't have the flexibility, they say, well, your price is too high. We're not going to talk about numbers, but it seems like if the price is too high --

MR. SCHNITZER:

It's not circular --

MR. WOOD:

Is it the same as --

MR. MARRONE:

Yes.

MR. WOOD:

Then you'd lose under either one.

MR. MARRONE:

It's based on what our marketing people see in the forward market, what they think we could do, what we can get in the forward market for our power. That's what sets the value, and then that value is translated into a heat rate and a capacity payment. Or it could be done as a must-take block. I can put it in heat rate. I can put in the capacity. I can give you a zero heat rate; just give it to me in capacity. But that's where the value is set.

If that's the true value, the value that my people believe that's in the forward market, to be fair to my shareholders, that's the minimum I want. And that's what sets the market price.

MR. WOOD:

But if he's got bids that are below that, then he should take those first.

MR. MARRONE:

Correct, and that's fine. But if we are going to come to a conference and talk about the fact that I can't figure out how to be flexible -- I know how to be flexible. It's just that there's constraint in the system that prevents me from saying, you can have zero to 500 megawatts, take it whenever you want.

MR. WOOD:

I don't think y'all are missing anything, from what I hear. Your value and how you package the value will determine your --

MR. MARRONE:

Right.

MR. SCHNITZER:

And we may have differences of opinion as to what it's worth that week. If those people tell them to bid this because that's what they think the market is on a day-to-day basis from Entergy's perspective -- there's no guarantee that everybody has the same view of what the market is going to be. And then when people don't get the same view, the transactions don't take place.

MS. MACKEY:

If there were some more price signals in the market, then Joe could tell his traders you should be looking at XYZ instead of ABC so we can start winning some bids here.

MR. WOOD:

In the current process, the consumer -- can y'all make multiple bids for the same week just to kind of test where the change is, or do you normally just make 1 bid? Because I've noticed that some people have encountered -- can you try some different permutations of what would work?

MR. MARRONE:

You can do that. I can't speak to whether we do.

MS. MACKEY:

Cottonwood does respond with multiple bids on multiple occasions.

MR. SCHNITZER:

If I can make one point. If Joe says that we put our bid in based on our view of what we can get in the marketplace, I'm not going to bid any lower than that. Then if he doesn't get the bid from us, then I'm assuming that he's going to sell it.

MR. MARRONE:

I have to make sure that my market people are correct.

MR. SCHNITZER:

Then you have received the best option available. I think that's the best outcome you're going to get.

MR. MARRONE:

That's not related to my inability to provide flexibility, and that's not going to change with the WPP. That's all I'm trying to say is that if flexibility is a problem, it's not going away with WPP.

MR. WOOD:

Mr. Carraway, you've been sitting here nice and quiet. What's on your mind? Tell me a little bit about Mississippi Delta.

MR. CARRAWAY:

Mississippi Delta Energy Agency is a consortium of 2 municipal utilities with a total load between 80 and 90 megawatts. Basically with most of the customer base in the Mississippi Delta, but Yazoo City splits a little bit between the Delta and getting into hills, or into a hilly area. Basically we have a high incidence of power level among our constituent base of our consumers. They are municipal utilities owned by the citizens of those two municipalities, and our problems are that MDEA serves as a bulk supplier for the 2 municipal utilities and we are a network customer of Entergy transmission.

Our problems are with both where we see the current weekly process that was mentioned in the New Orleans conference and the responses from the conference. There seemed to be some concern as to whether it was a problem with the scenario analyzer, and I thought we had made it clear to people at Entergy that our problem was that we were trying to utilize the tool that they supplied and area of "C" process, which is a scenario analyzer.

I think that the percentages that they came back with in their response was that about 95 percent of those requests had been granted, or based on the fact that we're trying to use that tool. We have used the scenario analyzer. We've been basically told in a meeting that was held in March of '04 that since this tool was out there, if it didn't pass the analyzer, you were wasting your time in submitting an Oasis request.

We've tried to utilize that, and we have run into several occasions in July and August and back in June, where we would run a scenario on a transaction, the transaction would show that it was transmission constrained. We would then run additional analysis from other resources, all around the Entergy boundaries, and we got the same answer, all pass. We would turn around. We had generation that was inside of our bus that belongs to us that is not listed as a network resource that we could run, and it would come back that we couldn't deliver capacity that was on our bus because it was transmission constrained.

We just feel like there is a problem with the tool, and one of the problems, as we understand, came out of the other conferences that have been held in Washington, that in the current process, what happens is that they're using the scenario analyzer when they make a transmission request to see if those bids are going to be able to be granted transmission service on the current process. And my understanding is that it blocks the analysis.

MR. RODGERS:

I think we need to break for lunch.

MR. WOOD:

If y'all don't mind, I'm going to bogart some time from the afternoon and only take a 50-minute lunch. Let's meet back here at 1:30.

(Whereupon a luncheon recess was taken.)

MR. WOOD:

If everone would take their seats, we'll get started back up.

We had the independent coordinator of transmission -- and the New Orleans hearing about this, and I think I would characterize those as meant for the -- I think we can use this afternoon's session on ICT to talk about how to improve the process to get to something that will work for both the applicant and the market participants.

MR. RODGERS:

I'd like to call on Rick Smith to go first for Entergy. I think he has about a 10-minute presentation, and then we'll get some response or comments from other folks at the table here.

MR. SMITH:

Good afternoon. Again, I'd like to express Entergy's appreciation for our federal regulators, our retail regulators joining us here today for an opportunity to really continue our discussions we had in New Orleans.

This afternoon, I'd like to briefly discuss two things. One is to respond to some of this suggested enhancement of the ICT proposal; and two, provide some thoughts on the independence of our ICT proposal.

On the first one, the suggested enhancements of the ICT proposal, I want to remind everyone that the genesis of the ICT proposal was the desire to obtain benefits for Entergy's retail customers and other wholesale market participants, short of the full RTO proposal which we judged was not feasible at the time. We believe the ICT proposal as structured would provide benefits to both our retail customers and other wholesale market participants and can be implemented in the year 2005.

We discussed some of these benefits at the last technical conference, and I won't repeat them now in detail except to remind all of us that the principal retail customer benefits stem from the transition expansion pricing proposal and the weekly procurement process. So when changes to the ICT are proposed as they have been, we ask ourselves two questions. With the proposed changes, will there be benefits to our retail customers? With the proposed changes, will the proposal be acceptable to our wholesale regulators?

To our knowledge, none of the parties suggesting changes have endorsed our transmission pricing proposal, and none have stated with their proposed changes that our pricing proposal would be acceptable to them as part of the compromise. And without approval of our transmission pricing policy in its proposed form, it would be difficult to answer the first question: Are there benefits for our retail customers in the beginning?

As to the second question, whether the proposed changes would be acceptable for our retail regulators, we expect that our retail regulators would also want to ensure the ICT proposal, in its totality, will provide benefits to our retail customers. In addition, there are also jurisdictional concerns. Recall that the ICT proposal was deliberately structured to provide extensive real-time oversight of Entergy's transmission operations, not control of those operations. This approach of oversight rather than control was designed to alleviate retail regulatory jurisdictional concerns and thereby facilitate implementation of the ICT proposal.

The approach was also designed to ensure independence. The ICT would be wholly independent for a number of reasons. It will meet all the independence criteria established for the RTO market monitors. There are provisions that would preclude the ICT being terminated absent the approval of the FERC. Moreover, since the last technical conference, we have had a series of meetings with the STP to discuss the cabinet that would serve as the ICT. We would expect that as an STP server that it would increase the market participants' confidence that the ICT would be independent.

Certain market participants have requested both the FERC and our retail regulators that the ICT assume greater responsibility over functions such as the granting of requests for transmission service calculations of ATC and AOCs.

Entergy recently responded to these requests in a filing made yesterday with NTOC. In that filing, Entergy pointed out that enhanced responsibility could raise the issue of who is the transmission provider allowing the ICT to perform these functions, such as Oasis administration and calculation of available flow gate capacity and available transfer capabilities could cause FERC to bring in the ICT, not Entergy, the transmission provider.

In an RTO context, the FERC is held as the RTO, not the transmission owner as the sole transmission provider. And as a result of this shift in roles is that the FERC obtains exclusive jurisdiction over the transmission components of the retail servers.

In addition to the jurisdictional concerns, the possibility that the ICT could become a transmission provider raises other questions, such as, would the ICT have Section 205 rights. You'd see unilateral changes to Entergy's oath, transmission business rules and AFC methodologies. Would the ICT be coming to Entergy to make decisions regarding purchase participation in a RTO?

Entergy's hope is that the FERC could resolve these concerns by finding that the ICT would not, by performing the additional limited functions of Oasis administration and AOC ATC calculations, become the transmission provider under Entergy's oath. If the FERC did, Entergy's retail regulators would be in a better position to evaluate these potential enhancements to the ICT functions.

That concludes my remarks, and we welcome questions.

MR. RODGERS:

Richard, let me ask if it's Entergy's belief that if the jurisdictional issue could be worked out over the functionality of the Oasis administration, ATC calculation, that it's Entergy's view that there could be additional benefits that would accrue, to be held right there, if the ICT performs its function?

MR. SMITH:

I would say we have not identified any benefits --

MR. WOOD:

What about regional transmission plans and having the ICT perform that function?

MR. SMITH:

Today, we do a certain amount of regional transmission functions. And on a short-term basis, they're going to be involved in all the detail plans anyway and probably involved in the decisions with STP. So the STP adds the ICT -- I think you're getting a lot of those benefits because they're going to be looking at our system, the systems that we interconnect with plus all of Entergy's. Our stance is that we need to maintain the long-term planning aspects of this, and I think they're going to be sitting there looking over our shoulders. And if it's STP, I think you'll hear from the majority of the benefits of regional planning.

MR. RODGERS:

Let me ask if it's Entergy's view that if the ICT is doing Oasis administration and ATC calculations, does Entergy believe that that makes it the transmission operator?

MR. NORTON:

You know, Steve, I seem to think it's more our question about how FERC would do that because it would be FERC who would decide whether that turned the ICT into the transmission provider under the old ATT. That's why Rick had said the FERC could remove that. We think that you could hold that consistent with the precedency, but it would be in your ballpark to make that decision.

MR. WOOD:

The CEO of PKM --

MS. HOCHSTETTER:

It seems to me that we've got a perfect precedent with us right in the room, and that's Southwest Power Pool. They have not yet been considered a federal public utility. The only step that they're going to be taking shortly which will put them in that category is becoming a full-fledged RTO. But it seems to me that you allow SPP to perform all the functionalities that they're performing right now for their members. And that would not render any of those functionalities of FERC jurisdictional, and FERC does not assert jurisdiction over SPP today as a federal public utility. At least, we haven't so far.

It's that step to becoming a RTO that's going to make the difference, so I guess I kind of pose that as an analogy if Entergy would take the step in adding all of the functionalities onto their ITT proposal that SPP is performing for its members today, including transmission. Could that not be done in the same manner that you look at SPP today, which is not FERC jurisdictional?

MR. BROWN:

I could probably give an even better example. Under the AEP-CSW merger order, the Commission required that AEP East facilities be turned over to be administered as an independent entity. We were not judged to be the quote, transmission provider, in that particular arrangement, which we did for nearly 4 years. We just turned that over as PJM undertook that, but we did receive requests for transmission service using AEP's tools, evaluated available transmission capability and granted or denied requests for service.

MR. WOOD:

It certainly did reduce the level of -- in that area where --

MR. SCHNITZER:

First, I have a question for Mr. Brown to clarify something that I don't know. Does SPP do ATT calculations at this time before becoming the RTO?

MR. BROWN:

Yes. Southwest Power Pool has been administering a regional tariff since '98 in which we calculate the capability of the entire system under SPP's functional control and administers that regional tariff on behalf of the individual transmission providers.

MR. SCHNITZER:

What I would say on the issue of who is the operator, the words we've used in other contexts to decide who's the operator of the facilities under our direction and who has the decisionmaking authority. Who has control over those facilities? Oasis administration, for example, is probably way out on the side of the spectrum that's not in control of the facility that's not running the facility. Sitting in the control room in real-time deciding this just happened; how are we going to re-configure the system and keep it all secure? That's on the opposite end. You are the operator.

Now, some of these functions, it's a little rare and is too extreme, but despite what PNN may have said to me, they have decisionmaking authority constituting them being the operator. How far does it go along that spectrum before we cross the line? We have a clear precedent on it because we haven't had that issue come up very often.

MR. MOOT:

I guess all I would add, Mike, is that this is a gray area, but several years ago the case involving MAP, and it was a different circumstance that MAP would be responsible for refunds, but the Commission did look at whether MAP and its agent would be transmission providers because of certain functions that were performed under a particular schedule. And it did involve things like ATC calculation processing, request for service. It is an older case, it's in a different context, but I think if the Commission was available to moving in this direction, the service precedent -- it's positive on the side of, you don't have to be the transmission provider. It's not necessarily the case that you're not the transmission provider.

MR. WOOD:

So someone has a complaint as to how that was administered?

MR. BROWN:

That was certainly the case in the AEP contract. We would not receive complaints. The complaint would go to AEP, and AEP would talk to us as a contract administrator saying, you're either doing your job wrong or you're doing it right.

MR. WOOD:

The people have issues over the last couple of years about transmission and things like that. That was the complaint brought against SPP.

MR. BROWN:

Well, there's two different things. There's SPP administering the SPP regional tariff, and then there's SPP administering the AEP East tariff. And my only point is, both of those are in different realms of the gray area because even under SPP administering the SPP regional tariff, RTO recognition, we were the transmission provider. We were not a transmission owner, but the fact that we were the transmission provider still did not make us FERC jurisdictional even though the tariff we administered was FERC jurisdictional.

Now that we've become an RTO, that relationship has changed. In the AEP tariff administration perspective, we were not viewed as the transmission provider. We were just an independent entity contracting with them to administer the provision of service over those facilities. So again, there's multiple areas where one is a provider, one's not, but still, one wasn't FERC jurisdictional. And so, there wasn't a shift, and the other -- again, a very gray area.

To me, that's one of the major distinctions in the ICT proposal, that it's the Entergy tariff. It's not a regional tariff. It's not an SPP tariff. It's an

Entergy tariff. They're the ones responsible for it. We're just a third-party contractor providing a service.

MR. RODGERS:

I had a question for Nick, if I could. Can you tell me, in your view, if there would be much added cost involved if SPP were to serve as the ICT for Entergy doing Oasis administration and AFC calculations? Would that add much more cost?

MR. BROWN:

No. And we filed comments with the Arkansas proceeding today to that effect. Quite frankly, right now Entergy's system is modeled in all of our systems to a great detail, and in many cases, to a detail greater than that of some of our own transmission owners just because of the high degree of interdependency between Entergy's transmission system and our transmission owners' systems.

Our systems are the same. We share data -- a very significant amount of data in real-time already today. There already is a high degree of coordination between Entergy and Southwest Power Pool.

MR. RODGERS:

And one other area of functionality is regional transmission planning. If that's the key word to perform that function as the ICT for Entergy, would that add much more cost to it?

MR, BROWN:

No. Again, it would not. In fact, we've been working with Entergy in the Lafayette, Louisiana area, and that was raised at the last conference, so we've had several meetings. I would characterize the product of that effort as being very successful. We met last week in Baton Rouge, and it has worked real well.

MR. BROWN:

And designers in SPP have lots of hands-on experience doing those functions in SPP RA in terms of ATC calculation, Oasis administration and regional transmission planning.

MR. BROWN:

Yes. Well, again, we've administered regional tariffs since 1988 and served as regional security coordinator since early '97 and, in fact, administered some Oasis nodes even farther to that time on behalf of our individual transmission owners.

MS. HOCHSTETTER:

Mr. Smith, if the FERC agreed to stick with their existing precedent with SPP and did assert jurisdiction over those additional functionalities that could be added to your IPP proposal, would you be agreeable to adding those to ICT proposals?

MR. SMITH:

What we would do is we'd present that act through al our retail jurisdiction and get their comments and supplement our -- have them file those with --

MS. HOCHSTETTER:

Since the only reason, as you've stated before, you don't think the retail regulators would approve anything else is because of jurisdictional shift, and I interpreted the main reason that you presented what you did in the ICT proposal, knowing that the additional functionalities would not present a jurisdictional shift. I can't imagine any retail regulator not wanting additional benefits for the same amount of dollars, so representing that that's the only issue that the retail regulators had. I think that that would be a relatively quick and easy process.

MR. SMITH:

As I said in my comments, as long as the transmission pricing proposals are put over with the adopted, I think it would go a long way to closing the gap, so to speak.

MR. ROGERS:

I'm not sure I'm understanding. Regardless of what the transmission pricing arrangement is, it was still presumably to be done so that you can have the Oasis administration done right or ATC calculated or regional transmission planning done. You can have benefits associated with each of those staying under various pricing. Correct for Mike? Not Mike?

MR. MOOT:

It's a quantitative question depending on how you want to answer it. As we talked in New Orleans, the principal quantifiable benefits associated with the ICT proposal with the, roughly, $15 million a year of additional costs. It basically came into two categories that Mr. Smith referred to with transmission pricing policy, connection policy and the WPP.

I'm a stranger to both two areas in particular. Entergy has prepared and filed a cost benefit study with all the jurisdictional analysis, and the ICT proposal is beneficial to the retail customers -- its benefits could be the quantifiable benefits exceed the costs. If you're not asking the question, we'll take away the transmission expansion pricing benefit and don't assume that in the calculation, and then ask the question, is the ICT in the customers' interest? I think you would have to attribute quality and the benefits of these factors that we have quantified would exceed the $15 million. We haven't asserted that the quantifiable benefits associated with planning according to Oasis administration and sales in the risk benefits of that magnitude.

MR. WOOD:
We're more interested in discrimination issues on the wholesale side that have not gone away -- legal bills that y'all spend on these things.
MR. SCHNITZER:
We certainly appreciate that too, but again, we're talking about with our retail regulators. They've asked the question directly. I believe with all the retail customers, is this proposal beneficial to retail customers? And our response is, that the key components that underlie that statement are two-dimensional.
MR. RODGERS:
In response to FERC's data request that y'all answered last month, your response to Question 7, you listed as one the quantifiable benefits associated with the ICT proposal are the following. The treatment of transmission upgrade associated with the MITI or NRIS network resource. Under the ICT proposal, these costs would be directly assigned to requests from the customer. This is a benefit to the SPP RTO alternative, and possibly, the status quo. By date, are you referring to the Entergy proposal for direct assignment and transmission upgrades for certain customers, participant funding?
MR. SCHNITZER:

It's the specific part of the ICT pricing proposal that says we implement the higher principal with respect to network service when there are no increment levels that the cost associated with qualifying any network resource that are not otherwise needed for expansion and which are not otherwise needed as far as the reliability baseline that those costs are borne via the customers generator in a manner to be determined between the two of them with the associated property rights that are articulated as part of that proposal.

MR. RODGERS:

How are you able to know, though, that those benefits associated with the ICT exist relative to the SPP transmission pricing proposal? Would that happen to be established yet?

MR. SCHNITZER:

The thing we were -- and perhaps this language is not as clear as it might have been, but I think in New Orleans, and I believe in the states themselves, we said SPP current pricing policy in response to questions we had in New Orleans. I think we agreed that if SPP puts out something that looks very different, and in their current policy it looks more like what the ICT proposal is, then that conclusion would be different. And we could rate that separately. We don't know that sitting here today, so the quantification must be the status quo.

MS. HOCHSTETTER:

I have a quick question in the $15 million cost. Would that not be less by having SPP do those functionalities since they're already staffed, up and running, have their systems, et cetera? I can't imagine -- we're not talking about starting from scratch.

MR. SCHNITZER:

Let me give part of the answer, and then Nick can give you the other half. But the cost management studies were from the perspective to benefit the retail customer. I think that was spelled out, I hope, so in that respect, we're comparing the $15 million of ICT contract policy bill. These would be what would otherwise be an estimated allocated share of SPP's operations costs.

Under the current SPP budget, our responsibility ratio share would be approximately the sane $15 million. So from an Entergy retail customer perspective, it appears to be about the same.

MR. BROWN:

That's probable -- I haven't looked at the specific numbers, which I could do readily or our office could do, rather. But that's probably pretty close.

MR. RODGERS:

If there's no other comments from the table here, why don't we hear some views from the others at the table? Anybody want to go first?

MR. NEWELL:

I appreciate the opportunity to speak with you once again about these issues

MR. RODGERS:

Let's just mention that you're representing Lafayette Utilities, so if you would just mention who you are.

MR. NEWELL:

I'm Gary Newell. I'm representing Lafayette Utilities. Let me just speak to a couple of points.

I feel the need to preface my comments with a very clear statement of what our position is on the ICT, and that is that the ICT is a very much second best alternative to RTO participation. I think we continue to feel that participation in an employee order 2000 compliant RTO is the best way to go. It's the best way to restore confidence in the markets in this region which, right now, is at a pretty low point, and it's the best way to bring investment in the region. I think we all agree that it's necessary and much needed. So by responding with what I hope is a constructive manner to some of the questions that are being raised in the context of the ICT proposal, I hope it's not misinterpreted to be any backtrack with what our position is.

We would much rather have an RTO. We figure that would be much better for the region as a whole. That being said, let me just comment quickly on a couple of the points that have been made about the benefits if the ICT proposal and the two that Mr. Smith identified on the transmission pricing proposal and the WPP.

A couple of quick comments. One is that in the transmission pricing proposal, and the Entergy folks are scrupulous in pointing out that those benefits are measured from the perspective of retail customers, those costs are not going away. Those costs are being shifted, and they're being shifted to other market participants and other folks in the marketplace. And if you're not on the receiving end of that shift, it's not exactly a benefit. It's an additional cost of doing business in the region.

And we can talk about the merits of the proposal as much as you find useful, but I think it's important to keep in mind when you call that a benefit. If you're a wholesale customer or somebody else, it's going to be getting the bill for that upgrade, and you're going to look at it as much of a benefit.

That is why independence is so key. If there is not an assurance that the ICT is irreproachably independent, then a lot of the ICT to administer a program that would permit that kind of shifting of costs among market participants and among competitors is very interesting.

The second point on the WPP is that I can't find benefits in the ICT proposal. Well, why is that not achievable as part of the ICT? I think it is. So I don't see those two going hand-in-hand. Moreover, I think there are greater benefits through Entergy's participation to make it an even bigger marketplace, a more regional market that goes beyond their program. And participation in the SPP would certainly accomplish that. I question whether that is a benefit that couldn't be obtained, and possibly larger benefits could be obtained through different courses of action.

Now, the other question that came up was, gee, are there any benefits associated with any functionality to the ICT? And the answer from Entergy was, no, they didn't see any. Well, some of them may not be quantifiable, but the one alluded to a moment ago, restoration of confidence in the operation of the marketplace, is a very important benefit that would translate into hard dollars-and-cents savings through, one would hope, additional entry by new competitors and additional investment.

And I think adding functionality to the list of duties, whether it be administration or ATC determinations, or what have you. The more you add, the more confidence I think there will be in the market and its operations and fairness of its operations, and that will bring dollar- and cents-type savings down the road. So it's hard to quantify now, but it's real and it's important.

One other quick point. Mr. Brown mentioned in his discussion about Lafayette and a certain kind of poster child. The lack of regional planning can result in some pretty horrible situations. You know we were just in discussions, and some of them were very successful. I would just be a little more leery. It's my nature to be very cautiously optimistic that there can be a combination of facilities and operating protocols that could start up next year that would alleviate or mitigate the number of TLRs in the region and the number of associated dispatch advance, but there are two caveats. One is the operating protocol. We need to decide what these operating protocols would have to be, and I cannot sit here today and tell you with any level of assurance that that would not be a difficult discussion.

The other point I need to make is the compensation issue. Somebody needs to step up to the plate and pay to re-dispatch. So far it's cost about

$200. It may cost a whole bunch more, and we remain very concerned about that, and I can imagine that it's another reason why we -- we're dealing with constraints before we get to the level of having to call TLRs 4, 5 and 6, but it also gives you a framework for making sure that the people who should get paid for re-dispatching to keep the lights on, get paid.

So, that was actually my introduction. I sort of feel like a little bit like the kid who's going to Macy's to talk to Santa when the questions were presented in a supplemental notice. What additional things would you like to see? And I've got my list, and everybody here has brought in a list. I don't know whether you go down the road right now or if you want to hear from the other folks first.

MR. WOOD:

That's fine.

MR. WEISHAAR:

Thank you, Mr. Chairman. Good afternoon, Commissioners. I'm speaking on behalf of SECA, Southeast Electric Consumers Association, which is a coalition of more than a dozen of the largest industrial consumers in the Southeast. We appreciate FERC's recognition and each of the state commissions' recognition that all the debate and the discussion and the analysis here is ultimately being in the betterment of the guys at the end of the line. We are the guys at the end of the line.

I'm happy to see that the ICT issue has been boiled down to just two issues; independence and functionality. And I say that tongue-in-cheek. We looked at the issue, and the ICT, as proposed, is an unacceptable outcome from our perspective. We would prefer the status quo to the ICT as proposed in our comments, including our post-technical comments. We've outlined two options to resolve the issues that we see in the system, and the issues included transmission access for the most efficient generation in the region. The issues include minimization of transmission congestion costs.

Our preferred option is like the common and municipals. Entergy's participation in a Commission-approved RTO. That does not necessarily mean an LMP. There was a proposal in comments of a non-market RTO, and I think that is an acceptable starting point. But the key factors that we're looking for are the scope beyond the Entergy system, independent operation, independent determinations about transmission capacity needs and the means to achieve those needs. That's our preferred option.

Option 2 is, I think there are things that are necessary to improve the ICT and still call it the ICT.

But really, there are a lot of steps that need to be taken to enhance the independence of that proposal and enhance the functionality of that proposal. We outlined the independence elements and the functional elements that we would like to see in our post-technical conference comments.

I will not burden the panel with repeating those here, but the bottom line is the ICT, as proposed, either needs to be beefed up or organizational order to take care of the problems that we receive in the system. Thank you.

MR. HAYDEN:

Thank you, Chairman Wood. I'm glad you all could be here on a rainy day in Mississippi. I'm John Hayden of Alpine, and actually, there was a lot of the things that I was going to say that have been said. So I'm just going to go home now.

I think the key thing that you hear is again from the previous panel with the Lafayette and the end user is one common theme -- two common themes. One is lack of independence. What we are talking about here is a big hurdle. We have to have independence, not only in transmission, but in procurement. You have Mr. Schnitzer sitting for both the WPP discussion and with the ICT. That just creates a conflict. You have the same people who are making decisions on how to serve load off its own generation. Well, without going through a lot of details, one of the things that did come up today that we have seen at Alpine, and some of the new ones have seen and some of the competitors have seen, the AFC, we're seeing a drastic swing in AFC. And why are we seeing these huge swings on a daily basis? Why are we seeing huge swings from day to day?

Number one, it evokes lack of market confidence. Rather than go through a whole list of these things, I think it comes down to -- we believe -- Alpine believes that the best solution is SPP. And Nick didn't pay me to say that. It is the best solution. We've got an RTO coming up, and we believe that they provide the best bang for the buck to all consumers of Entergy. It brings the most confidence to the merchant community. It will bring confidence to the investment community.

If we're not going to go there, then we get into, what's option 2? Well again, Bob brought it up. We need more functionality over the ICT. He touched on most of it. The municipals are suffering from a combination of claiming lack of regional planning and operational issues. And we believe that this ICT needs to have that functionality or bring that to the table.

There was something brought up related to ADP and their treatment of SPP's role as administrator of ADP tariff. While that definitely was a great step in the right direction with ADP, I will caveat one thing to that. ADP controlled the tariff and the operating guides to SPP to manage, and SPP did a very nice job of it, but there were flaws in the operating procedures and the tariff that were handed to SPP. So we, as merchants, got frustrated early on in that process. We'd call up Nick and his staff and say, Nick, what's going on here. And his comment would be, we're just administering the tariff, which they were. You'd call up ADP and say, I want to complain about this operating practice in your guide, and he'd say, call SPP. So there's some things to be concerned about.

MR. WOOD:

You couldn't --

MR. HAYDEN:

This was early on. That was four years ago in the early days. I can't remember specifics that popped up, but it seems that some of them related to timing of when you put your requests. And that slowly got addressed, but there was a period of runaround where they said, call them. I just wanted to make that little caveat about that.

I guess the only other comment I really want to make, there was some statements made, and I support power by both the panel here that if we go down this process, more involvement with the WPP or we would like to be able to participate in more forums, and there's been a little bit of an informal process in our lines that relates to Entergy working with some of the merchants and the like. And we would like to have more involvement in that process.

MR. CONWAY:

John Conway with the East Texas Co-op. Thank you very much. It's good to be with y'all again.

I had presented the East Texas Co-op position in New Orleans, and I won't spend the time repeating it. But what I would like to take a look at and have discussion on is, why should the ICT be more independent? What are the benefits from that, and how can we make that happen?

Short of an RTO, we, too, would like to see Entergy in an RTO in the SPP, but the view of reality and what would likely come about, short-term and long-term, What, short of that, can work to help all retail customers?

Entergy has customers, as they mentioned, both retail and wholesale. That's their native level. And there are retail customers in every one of the states and the city that's regulated by Entergy. RMEs or co-ops, we have retail customers. We're part of a native level. That's our concern. How can the entire retail customer base be benefited?

By the way, I'd like to ask a question of the Entergy folks. There was a reference made at the beginning of a filing being made yesterday. I believe, but I want clarification on this, please, that this filing was made in response to Commissioner Callahan's questions that Entergy look at various points that were made by the NRG companies as to ways to improve independence.

Many of the things that the NRG folks were talking about were very much what we and the others wanted to talk about. We'd like to see that, and I know that the Federal Commission has provided for a post-hearing conference, and we'll be using that at the forum. But the questions that NRG raised, why should the ICT be more independent? Our particular concern is the participant funding issues and the necessity of having a truly independent outfit run for 20 programs.

Before the Mississippi commission at the end of August, one of the questions that was asked of Entergy was, if you were king, how would you design SPP? And the answer came back as one of the things you could look to would be the CTRANS model. That CTRANS model had a very in-depth stakeholder process, and that is not something that we've advocated. That will help and be necessary for independence.

The CTRANS had independent -- in that case, it was an independent system operator, but a very much independent idea for regional implementing for a participant funding regime. Just taking part of the CTRANS model without taking things like the stakeholder process and without taking the indolence that the CTRANS had developed is a little like going out and buying a car and getting the chassis without the wheels. You're not getting a really good deal.

The other points that have been raised, and I was glad to hear the conversation earlier, was the jurisdictional question. What, short of an RTO, can be designed that will not trigger jurisdictional concern -- shifting what can be designed to do that. We've heard the outlines of how that can happen through contracts that would agree with everything that we've discussed in terms of the legal parameters of how to set up and using the SPP as an example. This is worth pursuing. There is a lot more that can be done by the ICT, I believe, without triggering the Commission's jurisdiction, and it would benefit every one of the states' retail customers in the region, the over-used term, a win-win.

One thing that I would put out is in terms of sitting and PCN authorities for states. That has absolutely got to stay with the state. I would not want East Texas or the cooperative to seem as advocating anything different, but I don't think FERC has, or even could, trespass on that authority, but I know that is a concern and a proper one.

The concern about the bundled sales, I would point out that right now, assuming the Commission has that authority, but right now because Entergy itself has jurisdiction. If the FERC had that jurisdiction, it could exercise it.

The creation of the ICT, a more developed ICT and an ICT along the lines that ETEC -- I don't see changing that balance in that concern or, indeed, tripping it and making it any worse.

Finally, the concept of large transmission investments to benefit the merchant generator. This is a participant funding issue. This one, we can discuss. We discussed it in New Orleans. We discussed it in comments. We don't believe it's designed for everything Entergy does, but having a truly independent ICT or implement -- one who design the base plan and has not taken that base plan as a give, one who goes out and looks to the regional best bang for the buck is the way to go.

MR. WOOD:

Mr. Brown, do you have anything to add?

MR. BROWN:

No.

MS. HOCHSTETTER:

I was just sitting here wondering if there would be merit to having this group, maybe not at this moment, but to have a group of stakeholders and retail commissions that were interested to come up with a list that they think is something short of triggering a jurisdictional shift to FERC, then starting with the functionalities that SPP is to perform today for its members and basically decide what that list ought to look like that everybody can agree on. And then -- could we collaboratively come up with a list that we think would enhance the ICT, but make it short of an RTO, short of a jurisdictional shift? And then maybe tee it up as an amendment in a FERC filing. Is that something that makes sense to everybody, including Entergy?

MR. SMITH:

Yes, I think that would. I think if we could formalize what we are talking about here and present it to the FERC for them to rule on, that would be great.

MR. CONWAY:

I think certainly we would be willing to participate in that. I didn't mention this in my opening comments, but the idea of just putting SPP in the shoes of the ICT doesn't really resolve our concerns. SPP has experience doing this because we're incapable of performing the necessary functions, and on its own, has a variable degree of independence that the Commission has found acceptable. But ultimately, if you plug SPP in as the ICT, there will be a contractual relationship between Entergy and SPP, and that relationship defines independence and functionality. I certainly agree with your suggestion, that if we're going to explore those lengths, it has to be, what is the scope of that contractual relationship in terms of both independence and functionality.

MR. WOOD:

The Commission does recent --

MR. SCHNITZER:

In response to Chairman Hochstetter's suggestion, I had a similar idea. I thought that it might be of use for stakeholders to try to get together a consolidated list that is more efficient for us to sort of sit down and say in our list, either change it to enhance independence or additional functions the we think would bring greater benefits.

My list already has 13 items.

MS. HOCHSTETTER:

I guess my thought and my vision on some similarities between -- was to engage in something including Entergy and the retail regulators so the standpoint that you'd be saving FERC's time and resources.

It might make sense for everybody but the adjudicators in this case to get together, everybody but the FERC Commissioners, to come up with something. Entergy's right. The retail regulators need to be involved in this too. We need to file something that everybody is comfortable with.

MR. CONWAY:

Chairman Hochstetter, what about a stakeholder process that some of us have been asking for on the ICT from the beginning? There have been stakeholder processes and meetings for the WPP, but I have no knowledge of any stakeholder process and meetings for the ICT. That would be an excellent first step, one that is long overdue and should be pursued.

MR. CALLAHAN:

I'd even bring the beer.

MR. HAYDEN:

Alpine would very much like to participate in such a process.

MR. RODGERS:

If I could sort of recap what I've heard from the panelist on that side of the table, it sounds like. In New Orleans, it seemed like that the panelists on that part of the table basically were drawing a line in the sand and saying RTO or nothing. What I'm hearing now is that while that is still the first preference, that nonetheless, that there's a feeling that if the independence issues could be worked out and there could be some added functionality to the ICT, then there may be a way to make this Entergy proposal acceptable.

MR. CONWAY:

I think you're right, if modifications could be made that would bring the proposal some of the increased indolence and some of the functions of trying to regionalize the decision in some fashion or getting involved in some of the regional planning framework. We might be able to get toward something that would gain broader stakeholder acceptance. I think that we need to realize that some of those enhancement and the stakeholders are wanting and are going to be a fairly tough sell to Entergy.

What I need to know from this is, what would the enhancements be? I started to get very close to the idea at the post-technical conference comments and the idea of a non-market RTO which would carry all the functionality of an RTO, but wouldn't have LMP-based management problems, features and opportunities associated with it. And so, I think certainly if we're going to go down that road, I think it would require clarification of these jurisdictional issues.

Right now, we're looking at the cost and not much benefit. The added functions that we want to put on there to get those benefits may be a bit of a tough sell.

I think those issues can be resolved. I guess an interesting question for the Commission's legal staff would be whether even if we were to confer on the ICT functions that might otherwise be thought to bring it within -- Could the Commission, nevertheless, say that we would not consider it to be?

I don't think the FERC can direct actions by the ICT. It's not doing its job. I don't see that that necessarily results in this jurisdictional shift.

MS. HOCHSTETTER:

I think my suggestion is that we need to make this as simple as we can. This does not have to be complicated. I keep going back to SPP. They've been doing this since the 1940s and they are doing everything that an RTO does today without the jurisdictional shift, with the exception of two things. One is actually having jurisdictional control over the facilities in the tariff language, and second is, operating a real-time balancing market. That's it.

You can correct me if I'm wrong, but those are the only two things that they currently do not do. That's the difference between a non-jurisdictional independent systems administrator and an Order 2000 compliant RTO. So this doesn't have to be tough. We've got an example in the room, and in this region, already. I mean, Entergy used to be part of SPP. It seems like we can fix this pretty easy without making a mountain out of a molehill.

MR. CALLAHAN:

I just have a question for the whole panel. And I'm sorry, Bob, that I haven't read your post-technical conference comments. But why is the ICT filed, not independent and how do we get it independent?

MR, HAYDEN:

I'll take a stab at answering. A couple of us said the we had rooted in our comments just some functionality elements that we would like to see in terms of an ICT. Let me state a couple of them. Full access to Entergy's facilities at any time, and the extent that Entergy can answer that its filing does accomplish it.

MR. CALLAHAN:

Full access to Entergy's facilities at any time. Is there something that would lead you to believe that the ICT would not have access to Entergy's facilities at any time? I would think they would have to have access.

MR. CALLAHAN:

If I remember correctly, they would be seeing the same thing that your guys in the Woodlands see wherever they put their office. It would be the same real-time.

MR. HAYDEN:

Take an example. You go to New England. You wouldn't want Northeast Utilities taking a look at ISO New England and having them be responsible for the auditing process. Entergy should have the same rights as others regarding ICT compensation, in terms of negotiating the payments for the ICT performance contract with the ICT. Setting that pay levels should not be an Entergy determination.

MR. CALLAHAN:

I don't think -- If I'm in the ICT, I'm going to negotiate. You're going to make money. You're negotiating to make money. If you sign the contract, you're happy that you're going to make money on Entergy or whatever you're doing.

MR. BROWN:

Well, not make money. We're a non-profit corporation. The way I would want to structure it is that it's a win-win situation for everyone involved. I think we can very efficiently provide those services to Entergy.

(Whereupon the proceedings were concluded.)